

**State of California**  
**Department of Water Resources**

**Determination of Revenue Requirements**  
**For the Period**  
**January 1, 2004, Through December 31, 2004**

**Submitted To**  
**The California Public Utilities Commission**  
**Pursuant To**  
**Sections 80110 and 80134 of the California Water Code**



**September 18, 2003**

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## **A. The Determination**

### **General**

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement between the State of California Department of Water Resources (the “Department”) and the California Public Utilities Commission (the “Commission”) dated March 8, 2002 (the “Rate Agreement”), the Department advises and notifies the Commission of its revenue requirement for the period January 1, 2004, through and including December 31, 2004 (the “2004 Revenue Requirement Period”). The Department has determined this revenue requirement in accordance with the Rate Agreement, California Water Code, Division 27 (the “Act”), and California Code of Regulations, Division 23, Chapter 4, Sections 510–517 (the “Regulations”). Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Indenture under which the Department’s Power Supply Revenue Bonds were issued (the “Bond Indenture”).

The Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the three California investor-owned utilities (the “Utilities” or “IOUs”) namely, Pacific Gas and Electric Company (“PG&E”), Southern California Edison Company (“SCE”) and San Diego Gas & Electric Company (“SDG&E”) in January and February of 2001. On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was enacted into law, containing, among other things, the Act. The Act authorized the Department to purchase the net short energy requirements of the customers. The “net short” is equal to total IOU customer energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department, in accordance with the Act, procured the net short requirements of the IOUs using a combination of long-term power contracts, short-term power contracts and wholesale energy purchases through the end of 2002. After allowing for the energy provided under the Department’s long-term power contracts, the amount of energy required to be purchased (initially on a short-term basis) to meet IOU customer needs, has been designated the “residual net short.”

To the extent the Department did not enter into long-term contracts, a greater volume of net short energy would have been purchased in the spot market between January 2001 and December 2002, the period during which the Department had the responsibility for the entire net short energy procurement. Similarly, after 2002, any energy not provided under the Department’s long-term contracts would be purchased by the three utilities, either as spot market purchases or under new long-term contracts authorized by the Commission under the annual energy procurement plan review process in accordance with Assembly Bill 57 (“AB 57”), which was enacted on September 24, 2002.

AB 57 provided for each of the utilities whose customers are served energy by the Department to resume procurement of the energy requirements of their customers that are not served by the Department, beginning January 1, 2003. The legislation further required each utility to provide to the Commission an energy procurement plan, including a description of the required energy products and a procurement plan for the utilities to meet

their residual net short energy needs. A copy of the full text of AB 57 is included in the administrative record compiled by the Department in support of this Determination.

At the time the Department entered into long-term contracts, Assembly Bill 57 had not been enacted and it was not clear when all three of the utilities would be sufficiently creditworthy to purchase their own residual net short energy requirements. The Commission commenced implementation of the energy procurement process contemplated by AB 57 for the first time in the fourth quarter of 2002.

On January 1, 2003, the IOUs resumed the responsibility of procuring the residual net short. Since that time, the Department's role in procuring power to meet the net short has been limited to the provision of power from power contracts entered into by the Department prior to January 1, 2003.

The costs of the Department's purchases to meet the net short requirements of the customers of the IOUs, including the costs of administering the long-term contracts, are to be recovered from payments made by customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations, the Rate Agreement and orders of the Commission. Among other things, the Rate Agreement contemplated a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).<sup>1</sup>

The Department funded its purchases of energy from January 17, 2001, through December 31, 2002, from three sources: payments collected from retail customers by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of \$4.3 billion issued in June 2001 (the "Interim Loan"). In October and November of 2002, the State issued \$11.263 billion of revenue bonds. The proceeds were applied to reimbursing the General Fund and payment of the Interim Loan, and certain debt service reserves and operating reserves were created. Repayment of the bonds will be made from the Bond Charge established in the Rate Agreement and from amounts in the related accounts, as described in more detail herein.

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<sup>1</sup> Under the Rate Agreement, "Department Costs" are all costs of the program other than "Bond Related Costs" and the "Retail Revenue Requirement" is the amount to be recovered from "Power Charges" on IOU customers (i.e., net of amounts recovered from Electric Service Provider customers for Department Costs). As a result, the assessment on customers of Electric Service Providers of charges to recover Department Costs ("Direct Access Power Charge Revenues") reduces the amount of the "Retail Revenue Requirement," but has no material impact on the amount of Department Costs. In the absence of final action to determine the amount Direct Access Power Charge Revenues, this 2004 Determination will generally treat the amount of the Retail Revenue Requirement as being the same as the amount of the Department Costs to be recovered from Power Charges on IOU customers, unless a distinction is necessary.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Determination contains information on the amounts required to be recovered, on a cash basis, in the 2004 Revenue Requirement Period.

A reconciliation of the Department's costs and revenues relative to revenue requirements through 2003 will be provided separately when actual data is available. Due to the time required for the California Independent System Operator ("CAISO" or "ISO") settlement process to be finalized, the information supporting the reconciliation of 2003 costs is expected to be available in or around May of 2004, and the "true-up" with respect to Department revenue requirements (as opposed to any true-up of the allocation of those requirements) will occur as new revenue requirements are determined. For example, this 2004 Determination takes into account preliminary actual results of Department operations through June 30, 2003 and revised projections of results of operations through the end of 2003.

For the 2004 Revenue Requirement Period, this determination contains information regarding the following<sup>2</sup>: (a) the projected beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts projected to be on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal, premium, if any, and interest on all bonds as well as all other Bond Related Costs as and when the same are projected to become due, and the projected amount of Bond Charges required to be collected for such purpose; and (c) the amount needed to meet the Department's Costs, including all Retail Revenue Requirements.

### **Determination of Revenue Requirements**

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the materials referred to in Section I), that its cash basis revenue requirement for the 2004 Revenue Requirement Period is \$5.390 billion, consisting of \$4.517 billion for Department Costs and \$0.873 billion for Bond Related Costs.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with its projected Department Costs ("Power Charge Accounts") for the 2004 Revenue Requirement Period. These figures are compared to those reflected in the July 1, 2003, Supplemental Determination for the 2003 Revenue Requirement period.

A summary and comparison of the Department's revenue requirements and accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

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<sup>2</sup> Where appropriate, the Department has provided information in this determination on a quarterly basis for the revenue requirement period. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis.

**TABLE A-1**  
**SUMMARY OF THE DEPARTMENT'S 2004 POWER CHARGE REVENUE**  
**REQUIREMENT AND POWER CHARGE ACCOUNTS <sup>1</sup>**

Line	Description	2004 <sup>2</sup>	2003 <sup>3</sup>	Difference
1	<i>Beginning Balance in Power Charge Accounts</i>			
2	Operating Account	756	1,273	(517)
3	Priority Contract Amount	-	-	-
4	Operating Reserve Account	630	777	(148)
5	<b>Total Beginning Balance in Power Charge Accounts</b>	<b>1,386</b>	<b>2,050</b>	<b>(664)</b>
6	<i>Power Charge Accounts Operating Revenues</i>			
7	Power Charge Revenues from Bundled Customers	4,483	3,288	1,195
8	Power Charge Revenues from Direct Access Customers	34	14	20
9	Extraordinary Receipts from Utilities	-	539	(539)
10	Other Power Sales	135	132	3
11	Interest Earnings on Fund Balances	31	32	(1)
12	<b>Total Power Charge Accounts Operating Revenues</b>	<b>4,683</b>	<b>4,005</b>	<b>678</b>
13	<i>Power Charge Accounts Operating Expenses</i>			
14	Administrative and General Expenses	59	49	10
15	Total Power Costs	4,698	4,628	70
16	Ancillary Services	-	22	(22)
17	Extraordinary Costs	71	-	71
18	<b>Total Power Charge Accounts Operating Expenses</b>	<b>4,828</b>	<b>4,698</b>	<b>130</b>
19	Net Operating Revenues	(145)	(693)	548
20	Net Transfers from/(to) Bond Charge Accounts	-	-	-
21	Total Net Revenues	(145)	(693)	548
22	<b>Ending Aggregate Balance in Power Charge Accounts</b>	<b>1,240</b>	<b>1,357</b>	<b>(116)</b>

2004 Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		Difference
<b>Operating Account:</b> This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month under a stress scenario.	285	348	(63)
<b>Operating Reserve Account:</b> Used to cover deficiencies in the Operating Account. It is sized as the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario.	579	630	(51)
<b>Total Operating Reserves:</b>	864	978	(114)

<sup>1</sup> Numbers may not add due to rounding.

<sup>2</sup> As proposed herein.

<sup>3</sup> As reflected in the Department's 2003 Supplemental Determination.

**TABLE A-2<sup>1</sup>**  
**SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND**  
**ACCOUNTS: BOND CHARGE ACCOUNTS<sup>1</sup>**

Line	Description	2004	2003	2004 minus 2003
				Inc/(Reduction)
		(\$ Millions)	(\$ Millions)	(\$ Millions)
1	<i>Beginning Balance in Bond Charge Accounts</i>			
2	Bond Charge Collection Account	146	77	69
3	Bond Charge Payment Account	382	211	171
4	Debt Service Reserve Account	927	927	0
5	<b>Total Beginning Balance in Bond Charge Accounts</b>	<b>1,455</b>	<b>1,215</b>	<b>240</b>
6	<i>Bond Charge Accounts Revenues</i>			
7	Bond Charge Revenues from Utilities	873	745	128
8	Revenue Bonds Net Proceeds	-	-	
9	Interest Earnings on Fund Balances	29	17	12
10	<b>Total Bond Charge Accounts Revenues</b>	<b>903</b>	<b>762</b>	<b>141</b>
11	<i>Bond Charge Accounts Expenses</i>			
12	Debt Service on Bonds	725	535	190
13	Other Bond Charge Account Expenses	-	-	
14	<b>Total Bond Charge Accounts Expenses</b>	<b>725</b>	<b>535</b>	<b>190</b>
15	Net Bond Charge Revenues	177	227	(50)
16	Net Transfers from/(to) Power Charge Accounts	-	-	
17	Total Net Revenues	177	227	(50)
18	<b>Ending Aggregate Balance in Bond Charge Accounts</b>	<b>1,632</b>	<b>1,442</b>	<b>190</b>

2003 Target Minimum Bond Charge Account Balances	Target (\$ Millions )	Target (\$ Millions )	
<b>Bond Charge Collection Account:</b> An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	75 - 78	41 - 76	
<b>Bond Charge Payment Account:</b> An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	253 - 656	136 - 227	
<b>Debt Service Reserve Account:</b> Established as the maximum annual debt service	927	927	

## **Future Adjustment of Revenue Requirements**

The Department reserves the discretion to revise its revenue requirements for the 2004 Revenue Requirement Period in recognition of the potential for significant or material changes in the California energy market, the status of market participants, the Department's associated obligations and operations, or any other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirement projections accordingly.

Several relevant factors are discussed in more detail within Section E.

## **B. Background**

### **The Act**

Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that "any just and reasonable" review shall be conducted and determined by the Department. In addition, Section 80134 of the Water Code provides that:

- “(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:
  - “(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.
  - “(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.
  - “(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.
  - “(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.
  - “(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and

General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.

“(6) The administrative costs of the Department incurred in administering this division.

“(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110.”

### **The Rate Agreement**

In February 2001, the Commission issued a decision adopting the Rate Agreement between the Commission and the Department establishing the procedures to be followed to calculate and adjust the charges to customers for Department power, such that the Department is assured of recovering its Retail Revenue Requirements.<sup>3</sup> The purpose of the Rate Agreement was to facilitate the issuance of bonds that enabled the repayment of the General Fund and Interim Loan, and the funding of appropriate reserves for the bonds. On November 14, 2002, the final bond issue was completed. The General Fund and Interim Loan were repaid.

The Rate Agreement establishes two streams of revenue for the Department. One revenue stream is generated from “Bond Charges” imposed for the purpose of providing sufficient funds to pay “Bond Related Costs.” Bond Charges are applied based on the aggregate amount of electric power sold to each customer by the Department and the applicable IOU, and, to the extent provided by final unappealable Commission orders, Electric Service Providers. Bond Related Costs include Bond debt service (including related Qualified Swap payments), credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds. Bond Charges are imposed upon customers within IOU service territories regardless of whether those customers purchase their energy supplies from the Department and/or IOUs or Electric Service Providers. The Rate Agreement requires the Commission to impose Bond Charges that are sufficient, together with amounts on deposit in the Bond Charge Collection Account, to pay all Bond Related Costs, as well as meet all Bond covenants as they come due.

The second revenue stream is generated from “Power Charges” imposed on customers who buy power from the Department, and is designed to pay for “Department Costs,” including the costs that the Department incurs to procure and deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements specified by the Department.

Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in, and accounted for under, the Electric Power Fund established by the Department under the Act.

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<sup>3</sup> California Public Utilities Commission, Decision 02-02-051, “Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources,” adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

Revenues from Power Charges are deposited into an "Operating Account." Funds in the Operating Account are used to pay Department Costs and are also transferred on a priority basis to a "Priority Contract Account." The Priority Contract Account is used to pay for the costs that the Department incurs under its Priority Long Term Power Contracts ("PLTPCs") which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs (such as Bond debt service).

In addition, the Department funds an "Operating Reserve Account" to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges are deposited into a "Bond Charge Collection Account." Funds in the Bond Charge Collection Account are transferred periodically to a "Bond Charge Payment Account." Funds in the Bond Charge Payment Account may only be used to pay Bond Related Costs. Funds in the Bond Charge Collection Account may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs if and only if amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient. If the Bond Charge Collection Account is used to pay amounts due under PLTPCs, the Bond Charge Collection Account is to be replenished or reimbursed from amounts when available in the Operating Account.

These Bond Charge and Power Charge accounts are further described in Section D.

#### **Prior Proceedings Relating to 2003 and the Projected Starting Balance for 2004.**

On August 16, 2002 the Department published its Determination of Revenue Requirement for 2003 (the "August 16, 2002 Determination"), and submitted that Determination with the Commission on August 19, 2002. On December 17, 2002, the Commission rendered Decision 02-12-045 "Opinion Adopting Interim Allocation Of the 2003 Revenue Requirement of The California Department of Water Resources." Decision 02-12-052 (Order Correcting Error) was also issued on December 17, 2002, correcting various tables and numbers contained in Decision 02-12-045. Decision 02-12-045 excluded \$29 million identified in relation to a power contract agreement between the Department and the California Consumer Power and Conservation Financing Authority ("CPA"). On February 13, 2003, the Commission issued Decision 03-02-031 amending Decision 02-12-045, as corrected by Decision 02-12-052, to allocate the aforementioned \$29 million. The Commission, in Decision 02-12-045, provided an interim allocation of the Revenue Requirement, and requested the Department submit a Supplemental Determination to include information available after the submittal.

On July 1, 2003, the Department issued its Supplemental Determination of Revenue Requirements for the period of January 1, 2003 through December 31, 2003 (the "2003 Supplemental Determination"). The Department determined, on the basis of the materials presented and referred to by the 2003 Supplemental Determination, its Retail Revenue Requirement for the period of January 1, 2003 through December 31, 2003, to be \$3.288 billion, after taking into account the application of Operating Account surplus funds described below and the amounts that had been generated from charges on the customers of Electric Service Providers.

The transition of responsibility for the procurement of the residual net short from the Department to the IOUs and a reexamination of possible future outcomes under stress scenarios permitted the Department to reduce the Minimum Operating Expense Available Balance ("MOEAB") from \$1 billion to \$348 million, and to reduce its Operating Reserve Account Requirement ("ORAR") from \$777 million to \$630 million. The \$777 million ORAR was based on 18 percent of total 2003 operating expenses as required by the Bond Indenture. The \$630 million target balance was calculated based on the maximum seven-month difference in operating expenses and revenues under a stress scenario, also consistent with Bond Indenture requirements. In addition, the reexamination of the Stress Case isolated the cash flow outcome resulting solely from the Stress Case as compared to the base case outcome. The total reduction in fund balance requirements was \$799 million from the fund balance requirements identified in the August 16, 2002 Determination.

The Department's revenues from retail customers projected in the August 2002 filing (assuming the same charges as implemented by the Commission in Decision 03-02-031) decreased by \$1.360 billion due to load and contract dispatch changes and the Department's ability to decrease account balance requirements, both described in Section E of the 2003 Supplemental Revenue Requirement.

Finally, the Department projects that it will receive from PG&E all applicable DWR charges for energy delivered to the PG&E customers. The amount of such charges relating to the period January 17, 2001 through the end of March 2003, that had not been remitted as of March 31, 2003, was estimated to be at least \$539 million.

Taking into account the factors summarized in the preceding paragraphs, and conditioned upon the receipt from PG&E of at least the \$539 million described above, the amount in the Operating Account on July 1, 2003, in excess of the amount required (if DWR charges were not modified) was projected to be \$1.002 billion. As a result, conditioned upon receipt of such \$539 million and assuming that DWR charges are not modified prior to July 1, 2003, the Department determined that its Retail Revenue Requirement for the period July 1, 2003 through and including December 31, 2003, net of the application of that \$1.002 billion is \$2.041 billion on a cash basis and that such requirement may be implemented in a manner that assumes that \$1.002 billion is available to pay Department Costs immediately as of July 1, 2003 (i.e., need not be reserved).

On September 4, 2003, the Commission adopted Decision 03-09-017 and Decision 03-09-018 relating to payment for under-remittances for DWR energy delivered to PG&E's service territory and allocation of the Department's 2003 Supplemental Revenue Requirement Determination among the service territories of the IOUs. These Decisions have been included as part of the administrative record supporting this Determination. With the inclusion of actual results through June 2003, and the modeling of D03-09-018, this 2004 Determination assumes a starting balance for the 2004 Revenue Requirement Period \$29 million higher than the balance projected in the Department's 2003 Supplemental Determination.

## **The 2004 Determination**

On July 18, 2003, the Department published its Proposed Determination of Revenue Requirements for 2004, consistent with the requirements of Sections 80110 and 80134 of the California Water Code and provided information consistent with the requirements of the Rate Agreement.

On August 6, 2003, the Department issued a Notice of Significant Additional Material, and provided additional material relied upon in making its Proposed Determination. The date for comments to be provided was also extended allowing sufficient opportunity for interested parties to review and comment on the Proposed Determination.

During the period between July 18, 2003, and August 14, 2003, when comments were due, the Department conducted conference calls, Webex presentations and responded to questions in an effort to assist interested parties in the review and understanding of the Proposed Determination.

On August 14, 2003, the Department received comments on the Proposed Determination from SCE, SDG&E, and PG&E. The comments are summarized and the Department's responses are included in Section H of this Determination.

The Proposed Determination published on July 18, 2003, included actual recorded data through March 2003.

After review of all comments and analysis of Decision 03-09-018 the Department has made the following changes in the 2004 Revenue Requirement as compared to the 2004 Proposed Determination.

1. Modeled Decision 03-09-018 and updated the Financial Model with actual results through June 2003, resulting in a projected ending 2003 aggregate balance in the Power Charge Accounts of \$1.386 billion, \$29 million higher than the balance projected in the 2003 Supplemental Filing.
2. Corrected the net debt service inputs reported on the "bonds" tab of the Financial Model.
3. Removed from Department Contract Costs the PG&E Interim Procurement Contracts.
4. Added the results of the re-negotiated Morgan Stanley Contract
5. Reflected the termination of the Calpeak NP A-Lodi, formerly Midway

Table B-1 summarizes the changes between the Proposed Determination and this Determination, for the Power Charge Revenue Requirement and Power Charge Accounts. Table B-2 summarizes the changes between the Proposed Determination and this Determination, for the Bond Charge Accounts.

**TABLE B-1**  
**SUMMARY OF THE DEPARTMENTS 2004 POWER CHARGE REVENUE**  
**REQUIREMENT AND POWER CHARGE ACCOUNTS COMPARED TO THE**  
**PROPOSED DETERMINATION<sup>1</sup>**

Line	Description	2004 <sup>2</sup>	2004 <sup>3</sup>	Difference
		(\$ Millions)	(\$ Millions)	(\$ Millions)
1	<i>Beginning Balance in Power Charge Accounts</i>			
2	Operating Account	756	748	8
3	Priority Contract Amount	-	-	-
4	Operating Reserve Account	630	630	-
5	<b>Total Beginning Balance in Power Charge Accounts</b>	<b>1,386</b>	<b>1,378</b>	<b>8</b>
6	<i>Power Charge Accounts Operating Revenues</i>			
7	Power Charge Revenues from Bundled Customers	4,483	4,652	(169)
8	Power Charge Revenues from Direct Access Customers	34	-	34
9	Extraordinary Receipts from Utilities	-	-	-
10	Other Power Sales	135	134	1
11	Interest Earnings on Fund Balances	31	31	1
12	<b>Total Power Charge Accounts Operating Revenues</b>	<b>4,683</b>	<b>4,816</b>	<b>(133)</b>
13	<i>Power Charge Accounts Operating Expenses</i>			
14	Administrative and General Expenses	59	59	-
15	Total Power Costs	4,698	4,794	(96)
16	Ancillary Services	-	-	-
17	Extraordinary Costs	71	71	-
18	<b>Total Power Charge Accounts Operating Expenses</b>	<b>4,828</b>	<b>4,924</b>	<b>(96)</b>
19	Net Operating Revenues	(145)	(108)	(37)
20	Net Transfers from/(to) Bond Charge Accounts	-	-	-
21	Total Net Revenues	(145)	(108)	(37)
22	<b>Ending Aggregate Balance in Power Charge Accounts</b>	<b>1,240</b>	<b>1,270</b>	<b>(29)</b>

2004 Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		Difference
<b>Operating Account:</b> This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month under a stress scenario.	285	286	(1)
<b>Operating Reserve Account:</b> Used to cover deficiencies in the Operating Account. It is sized as the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario.	579	591	(12)
<b>Total Operating Reserves:</b>	864	877	(13)

<sup>1</sup> Numbers may not add due to rounding.

<sup>2</sup> As determined herein.

<sup>3</sup> As reflected in the Department's 2004 Proposed Determination.

**TABLE B-2**  
**SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND**  
**ACCOUNTS: BOND CHARGE ACCOUNTS COMPARED TO THE PROPOSED**  
**DETERMINATION<sup>1</sup>**

Line	Description	2004 <sup>2</sup>	2004 <sup>3</sup>	Difference
		(\$ Millions)	(\$ Millions)	(\$ Millions)
1	<i>Beginning Balance in Bond Charge Accounts</i>			
2	Bond Charge Collection Account	146	236	(90)
3	Bond Charge Payment Account	382	447	(65)
4	Debt Service Reserve Account	927	927	-
5	<b>Total Beginning Balance in Bond Charge Accounts</b>	<b>1,455</b>	<b>1,610</b>	<b>(155)</b>
6	<i>Bond Charge Accounts Revenues</i>			
7	Bond Charge Revenues from Utilities	873	820	54
8	Revenue Bonds Net Proceeds	-	-	
9	Interest Earnings on Fund Balances	29	32	(3)
10	<b>Total Bond Charge Accounts Revenues</b>	<b>903</b>	<b>852</b>	<b>51</b>
11	<i>Bond Charge Accounts Expenses</i>			
12	Debt Service on Bonds	725	725	-
13	Other Bond Charge Account Expenses	-	-	
14	<b>Total Bond Charge Accounts Expenses</b>	<b>725</b>	<b>725</b>	<b>-</b>
15	Net Bond Charge Revenues	177	126	51
16	Net Transfers from/(to) Power Charge Accounts	-	-	
17	Total Net Revenues	177	126	51
18	<b>Ending Aggregate Balance in Bond Charge Accounts</b>	<b>1,632</b>	<b>1,737</b>	<b>(105)</b>

2003 Target Minimum Bond Charge Account Balances	Target (\$ Millions)	Target (\$ Millions)
<b>Bond Charge Collection Account:</b> An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	75 - 78	75 - 78
<b>Bond Charge Payment Account:</b> An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	253 - 656	319 - 721
<b>Debt Service Reserve Account:</b> Established as the maximum annual debt service	927	927

<sup>1</sup>Numbers may not add due to rounding.

<sup>2</sup>As determined herein.

<sup>3</sup>As reflected in the Department's 2004 Proposed Determination.

## **C. The Department's Determination of Revenue Requirements for The Period of January 1, 2004 Through December 31, 2004**

### **Retail Revenue Requirement Determination**

For the 2004 Revenue Requirement Period, the Department's revenue requirements consist of Department Costs and Power Charge revenues, and Bond Related Costs and Bond Charge Revenues.

Department Costs include:

- (1) Costs associated with power supply to be delivered under the Department's Priority Long-Term Power Contracts ("PLTPCs");
- (2) Administrative and general expenses;
- (3) Extraordinary costs (gas contract collateral), and
- (4) Operating reserves as determined by the Department (see Table A-1).

Power Charge revenues include:

- (1) Revenues from other power sales;
- (2) Interest earnings; and
- (3) Power Charge revenues (including both Power Charge Revenues and Direct Access Power Charge Revenues, as those terms are defined in the Bond Indenture).

There are no provisions included in Department Costs for the procurement of the residual net short by the Department during 2004.

During 2004, the Department projects that it will incur the following Department Costs: (a) \$4.698 billion for long-term power contract purchases to cover the net short requirement of customers; (b) \$59 million in administrative and general expenses; (c) \$71 million in extraordinary expenses; and (d) \$(145) million in other net changes to Power Charge Accounts. This results in a total of \$4.683 billion in Department Costs.

Funds to meet these costs (in addition to surplus operating reserves) are provided from (a) \$135 million from the Department's share of power sales revenues to the spot market; (b) \$31 million of interest earned on Power Charge Account balances; (c) \$34 million Direct Access Surcharge Revenues; and (d) \$4.483 billion from Power Charges Revenues and Direct Access Power Charge Revenues.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2004 Revenue Requirement Period.

**TABLE C-1**  
**POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:**  
**RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT**

Line	Description	Amounts for 2004 Revenue Requirement				
		Q1	Q2	Q3	Q4	Total
1	<i>Power Charge Accounts Expenses</i>					-
2	Power Costs	1,149	1,011	1,340	1,198	4,698
3	Administrative and General Expenses	15	15	15	15	59
4	Extraordinary Cost	71	-	-	-	71
5	Debt Service	-	-	-	-	-
6	Net Transfers from/(to) Bond Charge Accounts	-	-	-	-	-
7	Net Changes to Power Charge Account Balances	(66)	9	(143)	55	(145)
8	<b>Total Power Charge Accounts Expenses</b>	<b>1,169</b>	<b>1,035</b>	<b>1,211</b>	<b>1,268</b>	<b>4,683</b>
9	<i>Power Charge Accounts Revenues</i>					
10	Surcharge Revenues	4	9	10	11	34
11	Other Power Sales Revenues	39	23	31	42	135
12	Interest Earnings on Power Charge Account Balances	11	-	21	-	31
13	Net Loan Proceeds	-	-	-	-	-
14	Retail Customer Power Charge Revenue Requirement	1,115	1,004	1,150	1,215	4,483
15	<b>Total Power Charge Accounts Revenues</b>	<b>1,169</b>	<b>1,035</b>	<b>1,211</b>	<b>1,268</b>	<b>4,683</b>

Bond Related Costs include:

- (1) Debt service on the Bonds (including related Qualified Swap payments); and
- (2) Changes to Bond Charge Account balances.

Bond Related Revenues include:

- (1) Interest earned on Bond Charge Account balances; and
- (2) Bond Charge Revenues (including from customers of Electric Service Providers).

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2004 Revenue Requirement Period.

**TABLE C-2**  
**POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:**  
**RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT**

Line	Description	Amounts for 2004 Revenue				
		Q1	Q2	Q3	Q4	Total
1	<i>Bond Charge Accounts Expenses</i>					
2	Debt Service Payments	36	419	36	235	725
3	Other Bond Charge Account Expenses	-	-	-	-	-
4	Net Changes to Bond Charge Account Balances	166	(213)	228	(3)	177
5	<b>Total Bond Charge Accounts Expenses</b>	<b>202</b>	<b>205</b>	<b>264</b>	<b>232</b>	<b>903</b>
6	<i>Bond Charge Accounts Revenues</i>					
7	Interest Earnings on Bond Fund Balances	5	-	24	-	29
8	Revenue Bonds Net Proceeds	-	-	-	-	-
9	Net Transfers from/(to) Power Charge Accounts	-	-	-	-	-
10	Bond Charge Revenue Requirement	197	205	239	232	873
11	<b>Total Bond Charge Accounts Revenues</b>	<b>202</b>	<b>205</b>	<b>264</b>	<b>232</b>	<b>903</b>

During the 2004 Revenue Requirement Period, the Department projects that it will incur the following Bond Related Costs: (a) \$725 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds, and (b) \$177 million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of \$903 million.

Funds to meet these requirements are provided from (a) \$29 million in interest earned on Bond Charge Account balances and (b) \$873 million from Bond Charge Revenues (including from customers of Electric Service Providers). There are no projected net transfers from Power Charge Accounts.

In aggregate, the Department's total cash basis expenses are \$5.553 billion. Revenues from interest earned and other power sales are \$195 million, and net changes in fund balances are \$(32) million, resulting in combined customer revenue requirements of \$5.391 billion.

#### **D. Assumptions Governing the Department's Projection of Revenue Requirements for the 2004 Revenue Requirement Period**

This 2004 Determination is based on a number of assumptions regarding sales, power supply, natural gas prices, off-system sales, demand side management and conservation, and administrative and general expenses.

## Load and Sales Forecast

The Department obtained the most recent forecasts of customer loads from each IOU in April 2003. The forecasts received from the IOUs were compared with other relevant information including recorded IOU sales data, forecasts prepared by the California Energy Commission (“CEC”) and the Western Electricity Coordinating Council (“WECC”). A loss factor was applied to the IOU estimates of sales at the customer’s meter to obtain the total amount of energy required to meet customer electricity requirements. The loss factors utilized in developing the estimate of the electricity requirements were as follows.

**TABLE D-1  
LOSS FACTORS UTILIZED**

Utility	Distribution	Transmission	Total
PG&E	7.0%	2.0%	9.0%
SCE	7.4%	1.6%	9.0%
SDG&E	4.0%	1.8%	5.8%

Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in “independent” variables (such as employment growth) to “dependent” variables (such as electricity sales by the end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.

Table D-2 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this 2004 Determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E’s service area prepared by Economy.com. SCE derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. (“DRI”), and SDG&E” relied on a DRI forecast of economic trends in its service area.

**TABLE D-2**  
**MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS**  
**OF THE INVESTOR-OWNED UTILITIES**

	<u>PG&amp;E</u>	<u>SCE</u>	<u>SDG&amp;E</u>
Growth Assumptions:			
Population Growth <sup>1</sup> .....	1.0	1.8	1.4 <sup>3</sup>
Number of Households <sup>1</sup> .....	1.3	1.0	1.7 <sup>3</sup>
Non-Farm Employment <sup>1,2</sup> .....	1.0	1.1	2.1 <sup>3</sup>
Heating Degree Days .....	20-Yr.	30-Yr.	20-Yr.
	Avg.	Avg.	Avg.
Cooling Degree Days .....	20-Yr.	30-Yr.	20-Yr.
	Avg.	Avg.	Avg.

Source: PG&E data from work papers submitted in PG&E's Notice of Intent for its 2003 GRC. SCE data from Notice of Intent for Test Year 2003 GRC. SDG&E data provided by the IOU.

<sup>1</sup> Percent per year increase during 2002 and 2003, except as noted.

<sup>2</sup> Actual growth during 2001 was 1.2 percent statewide, according to the State Department of Finance.

<sup>3</sup> Average annual percent growth from 2000 through 2006.

### **Sources of IOU Forecasts**

The Department obtained from each IOU the load forecast used in its respective long-term resource plan, filed with the Commission on April 15, 2003. PG&E projects 2004 total retail sales of 85,822 GWh, SCE projects total retail sales of 90,035 GWh, and SDG&E projects total retail sales of 20,390 GWh. These projections do not reflect any reductions for transmission and distribution losses.

### **Hourly Load Shapes**

The Department utilized total retail and Direct Access hourly load shapes provided by each of the IOUs in 2002. Hourly energy and peak usage was estimated by applying percentage of sales in each hour to annual energy estimates provided by the IOUs.

### **Self-Generation**

To determine the outlook for self-generation, the Department prepared a forecast of the potential increase in self-generating capacity in the IOU service areas. The forecast considered a range of factors including: (a) self-generation and/or renewable resource incentive programs and initiatives administered by the CEC, the Commission, the CPA, and the CAISO; (b) recent price increases, cost responsibility surcharges, the suspension of Direct Access, increased concerns over service reliability, and ongoing efforts to standardize interconnection requirements through the Commission's Rule 21 proceedings; and (c) potential barriers and market restraints to the expansion of self-generation. The forecasted self-generation is presumably incorporated in the IOU forecasts. Therefore, the estimate of self-generation does not result in a net reduction in energy and demand

requirements compared with the forecasts prepared by the IOUs. Trends in self-generation capacity will be monitored and these assumptions will be revisited if warranted.

### **Direct Access**

Direct Access was suspended as of September 20, 2001 by Commission Decision 02-03-055. Electric end-users, who elected to acquire electricity supplies from alternative providers on or before September 20, 2001 and have not since returned to bundled service, continue to be eligible for Direct Access service. Decision 02-03-055:

- Suspends new Direct Access Servicing Arrangements until the Department is no longer providing power to customers.
- Prohibits the IOUs from accepting any new Direct Access Service Requests not already approved by the Commission, including requests from existing qualified Direct Access end-users that wish to add new Direct Access locations or accounts to their service.<sup>4</sup>
- Contemplates the possible establishment by the Commission, at a future date, of a charge on Direct Access customers (“Direct Access Charge”). The Direct Access Charge is intended to prevent cost shifting as a result of Direct Access migration prior to September 20, 2001.

In Decision 02-11-022, the Commission ordered certain classes of Direct Access customers to pay a cost responsibility surcharge (“CRS”). The CRS was capped at 2.7 cents per kWh and includes one or more of the following charges, depending upon the customer:

- DWR Bond Charge: debt service costs associated with the Department’s 2001 undercollection of power costs.
- DWR Power Charge: incremental costs to bundled customers resulting from the migration of load to Direct Access after July 1, 2001.
- Tail Competition Transition Charge (“CTC”): qualifying, uneconomic utility retained generation costs.
- HPC: historical procurement charge for year 2000 undercollection of power costs. Currently, this is only for SCE customers.

On May 8, 2003, the Commission issued Decision 03-05-034 regarding rules as to the right of customers to switch between Direct Access and bundled service on an ongoing basis. The Decision provides customers who were on Direct Access after September 20, 2001, but returned to bundled service subsequently, a 45-day safe harbor to return to Direct Access service. Under such circumstances, they will pay the applicable CRS component charges. Returning Direct Access customers who remain on bundled service beyond the 45-day safe harbor will be required to make a three year commitment to the IOU.

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<sup>4</sup> However, these customers may renew their Direct Access service contracts upon their expiration or transfer them to a new service location as long as the load served is of comparable size.

Direct Access customers may elect to return to bundled service but must provide the IOU six months advance notice, and must likewise make a three year commitment to the IOU. In the event customers return within the six month waiting period, they will pay the IOUs spot price of energy. They will also be responsible for their share of any CRS undercollection incurred while they were Direct Access customers.

On July 10, 2003, the Commission adopted Decision 03-07-030, which maintains the current CRS cap adopted by Decision 02-11-022. Decision 03-07-030 also modified the collection priority of the CRS components by placing the utilities' CTC component before the DWR power charge component in priority once the utilities' CTC component is determined. The Department anticipates that the utilities' CTC component for 2001-2003 will be determined prior to 2004.

Based on the above, the Department expects Direct Access to remain at a constant level statewide in 2004. The Department's Direct Access estimates, which are based on data provided by the Utilities in April 2003, are as follows.

**TABLE D-3  
DIRECT ACCESS PERCENT OF LOAD**

	Percentage of Total Load
Pacific Gas and Electric Company	10.1%
Southern California Edison Company	14.0%
San Diego Gas and Electric Company	16.6%
<b>Statewide</b>	<b>12.6%</b>

#### **PG&E Sales to Western Area Power Administration ("WAPA")**

Contract 2948A, signed in 1967, governs the interconnection of PG&E's and WAPA's transmission and distribution systems and the integration of their loads and resources. The contract allows WAPA to integrate PG&E's fossil-fueled and other generating resources with the hydropower resources of the federal Central Valley Project ("CVP") and deliver this "firmed" energy to preference power customers—generally government and municipal entities—pursuant to Federal reclamation law. In return, PG&E receives access to surplus CVP hydroelectric generation, which is less expensive than other resources available to PG&E. Virtually all of WAPA's 73 preference power customers are located in the PG&E service region in northern California.

During 2004, PG&E is assumed to provide 4,467 GWh of firming energy to WAPA. The forecast is based on WAPA's March 29, 2002 rolling 12-month forecast of preference power customer loads and the long-term average of CVP hydroelectric generation and U.S. Bureau of Reclamation pumping requirements contained in WAPA's July 2000 Green Book for the Post-2004 Marketing Plan. The Department also forecasts that WAPA will

purchase 86 GWh of spot market energy during hours when the NP 15 price is projected to be lower than the cost of firming energy from PG&E. These spot market purchases reduce the amount of firming energy provided by PG&E.

The Department modeled PG&E sales to WAPA in PROSYM as a “negative bilateral” that reduces PG&E’s Utility Retained Generation (“URG”) and thereby increases the quantity of energy supplied by the Department. The sale is modeled as a base load contract and the peak MW for each month is computed by dividing the monthly energy by the number of hours in the month. Although this may somewhat overstate the peak MW provided to WAPA during the summer months, the impact on the Department’s overall revenue requirement is not expected to be material. There are no comparable “other load requirements” for the other IOUs.

Contract 2948A expires at the end of 2004. The Department has assumed that this contract will not be renewed or replaced with another, similar contract.

### Peak Load and Energy Calculations

Table D-4 provides the peak megawatt demand forecast for each IOU in 2004. Based on their respective load shapes, the total peak demand for PG&E, SCE, and SDG&E occur in August 2004. The total IOU peak demand is the sum of the individual peaks. Due to load diversity, the coincident peak computed in PROSYM and experienced under actual conditions is likely to be lower.

**TABLE D-4**  
**ESTIMATED PEAK DEMAND<sup>5</sup>**

	Amounts for the Revenue Requirement Period (Megawatts)
<b>Pacific Gas and Electric Company</b>	
Peak Demand <sup>6</sup>	17,591
Less Direct Access	1,137
Peak Demand After Adjustments <sup>7</sup>	16,454
<b>Southern California Edison Company</b>	
Peak Demand	19,278
Less Direct Access	2,305
Peak Demand After Adjustments	16,973
<b>San Diego Gas and Electric Company</b>	
Peak Demand	4,005
Less Direct Access	470
Peak Demand After Adjustments	3,535
<b>All Investor-Owned Utilities</b>	
Peak Demand	40,874
Less Direct Access	3,912
Peak Demand After Adjustments <sup>8</sup>	36,962

<sup>5</sup> All values presented in the table are before any reduction for transmission and distribution losses.

<sup>6</sup> Includes adjustments due to price elasticity effects.

<sup>7</sup> For all three IOUs, these amounts are intended to represent peak demands that must be met by electric generating resources or power purchases or a combination of the two.

<sup>8</sup> Represents the sum of the individual IOU amounts. The actual value at the time of the system’s coincident peak may be lower.

Table D-5 shows the estimated gigawatt hours of energy requirements expected during 2004.

**TABLE D-5**  
**ESTIMATED ENERGY REQUIREMENTS<sup>9</sup>**

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
<b>Pacific Gas and Electric Company<sup>10</sup></b>	
Energy Requirements <sup>11</sup>	85,822
Less Direct Access	8,646
Energy Requirements After Adjustments <sup>12</sup>	77,176
<b>Southern California Edison Company</b>	
Energy Requirements	90,035
Less Direct Access	12,579
Energy Requirements After Adjustments	77,456
<b>San Diego Gas and Electric Company</b>	
Energy Requirements	20,390
Less Direct Access	3,378
Energy Requirements After Adjustments	17,012
<b>All Investor Owned Utilities</b>	
Energy Requirements	196,247
Less Direct Access	24,604
Energy Requirements After Adjustments	171,643

### Power Supply Related Assumptions

Two types of power supplies needed to meet the requirements of the three IOUs were considered by the Department in this 2004 Determination: (a) Supply from Priority Long-Term Power Contracts and (b) the residual net short of the three IOUs.<sup>13</sup>

<sup>9</sup> All values presented in the table are before reduction for transmission and distribution losses.

<sup>10</sup> Amounts shown exclude 4,467 GWh of requirements associated with the company's contract with the Western Area Power Administration ("WAPA").

<sup>11</sup> For all three utilities, includes adjustments on account of price elasticity effects.

<sup>12</sup> For all three IOUs, these amounts are intended to represent energy requirements that must be met by electric generating resources or power purchases or a combination of the two.

<sup>13</sup> While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2004 Revenue Requirement Period.

Table D-6 below shows, for the 2004 Revenue Requirement Period, the combined estimated peak demand for the three IOUs, the estimated peak demand after adjustments, estimated supplies from generation retained by the three IOUs,<sup>14</sup> the resulting net short, the expected supply from the Department's Priority Long-Term Power Contracts, and the residual net short.

**TABLE D-6**  
**ESTIMATED NET SHORT PEAK DEMAND, CAPACITY**  
**FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE**  
**DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT CAPACITY**

	Amounts for the Revenue Requirement Period (Megawatts)
<b>All Investor Owned Utilities</b>	
Peak Demand <sup>15</sup>	40,874
Peak Demand After Adjustments	36,962
Less, Supply from Utility Resources	22,745
Net Short	14,217
Less, Supply from the Department's Priority Long Term Power Contracts	11,696
Residual Net Short (Surplus)	2,519

<sup>14</sup> For purposes of this Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QF's") and other bilateral contracts.

<sup>15</sup> See the discussion under "Load and Sales Forecast Assumptions" for an explanation of the source of data on peak demand for each of the three IOUs.

Table D-7 below presents similar combined information for the three IOUs in terms of energy requirements during the 2004 Revenue Requirement Period.

**TABLE D-7**  
**ESTIMATED NET SHORT ENERGY, SUPPLY**  
**FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE**  
**DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT**

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
<b>All Investor Owned Utilities</b>	
Energy Requirements After Adjustments	171,644
Supply from Utility Resources	118,612
Net Short	53,032
Supply from the Department's Priority Long Term Power Contracts	58,872
Off-System Sales <sup>17</sup>	16,300
Residual Net Short (Surplus) <sup>18</sup>	10,460

For informational purposes, Table D-8 shows, for the 2004 Revenue Requirement Period, the expected average cost (in \$/MWh) on a quarterly basis for the Department's Priority Long Term Power Contracts.

**TABLE D-8**  
**ESTIMATED POWER SUPPLY COSTS**  
(Dollars per Megawatt-Hour)

	<b>LONG-TERM PRIORITY CONTRACTS</b>
Quarter 1 – 2004	80
Quarter 2 – 2004	84
Quarter 3 – 2004	82
Quarter 4 – 2004	80

Table D-9 shows, on a quarterly basis for the 2004 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from Priority Long-Term Power Contracts, and the residual net short.

**TABLE D-9**  
**NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS,**  
**OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2004**

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long- Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWh)
Q1-2004	11,187	14,061	\$1,110	(4,369)	\$112	1,495
Q2-2004	11,406	13,253	1,043	(3,468)	82	1,622
Q3-2004	15,842	16,175	1,305	(3,169)	86	2,837
Q4-2004	14,399	15,310	1,205	(4,969)	152	4,058
Total	52,834	58,798	4,663	(15,976)	433	10,011

### Natural Gas Price-Related Assumptions

Natural gas prices have undergone an upward shift in the price curve beginning in mid-2000. As a result of a combination of factors including supply availability, pipeline constraints, storage levels and weather patterns, natural gas prices have risen above a price band that lasted for most of the previous decade. The “California crisis” in 2000-2001, including market manipulation, also contributed to sustained increases in natural gas prices.

For the gas price forecast underlying this 2004 Proposed Determination (the same gas price forecast was used for the 2003 Supplemental Determination), there have been adjustments from the forecast used in the August 16, 2002 Determination. The first adjustment in January 2003 began with a starting price approximately \$1.00 per MMBtu higher than the previous price forecast. The base forecast also incorporated an adjustment to another key variable, weather. Based upon the record warm winter in 2002 (January - March 2002), the prior forecast used about 10 percent fewer degree days than normal, in anticipation that total 2002 degree days would remain lower than normal. The 10 percent fewer degree days had the impact of reducing the previous price forecast by \$0.30 per MMBtu from what it would have been with normal weather. The third key change in the current price forecast was to recalibrate the drilling variable. The drilling variable accounts for the number of wells that need to be completed in order to produce sufficient natural gas to meet projected demand. Recalibrating the well depletion assumptions behind the drilling variable results in an additional 1,800 wells being required in almost all forecast years and increasing the price by approximately \$0.43 per MMBtu.

Nationally, the winter of 2003 was one of the coldest winters on record, particularly in the Northeast consuming region. The cold weather, combined with abnormally strong storage withdrawal volumes, resulted in low storage levels and contributed to much higher than anticipated short-term prices during the first quarter of 2003, with lingering price effects thereafter. The March monthly index price of \$9.11 per MMBtu, for example, was much higher than anticipated (\$3.81 per MMBtu was the forecasted price) and had the effect of potentially skewing the entire 2003 year forecast. In March, an extraordinary adjustment to the January 2003 price forecast was prepared that adjusted short term prices experienced in the first quarter to actual prices and "shaped" the balance of the spring shoulder and summer prices. These prices were then re-run using the Department's proprietary long term price forecasting model. The model relates annual natural gas prices to prior period prices, reflects weather as average heating or cooling degree days, and utilizes a variable for drilling activity and well completions to produce a forward price at Henry Hub. Not surprisingly, these changes had the greatest impact upon near term prices with the annual price for 2003 increasing by \$1.07 per MMBtu from the previous forecast. For the following years, the price changes are projected to be less significant, increasing by \$0.31 per MMBtu in 2004 and \$0.11 per MMBtu in 2005. By 2006 the short-term effects of the winter of 2003 prices are expected to have no effect on the previous forecast.

Prices at Henry Hub determined by the model are then adjusted by adding a "basis" differential to the Henry Hub price to arrive at the Southern California Border. Delivered prices in California are determined by adding the cost of intrastate transport to the California border price. Resulting gas prices for 2003 and 2004 at the Southern California Border, Malin and PG&E's Citygate are shown in Table D-10.

**TABLE D-10**  
**NATURAL GAS ASSUMPTIONS**  
**(DOLLARS PER MMBTU)**

	Socal Border	Malin	PG&E Citygate
2003	5.17	4.86	5.26
2004	4.37	4.09	4.45

### **Hydro Condition Assumptions**

Normal hydro conditions are assumed for both California and the Pacific Northwest for 2004 and 2005. The CEC has indicated it expects nearly 108 percent of normal hydro conditions for 2003, due primarily to a very wet April 2003. The CEC also indicated that hydrological conditions for 2003 were improving in the Pacific Northwest, but had not returned to completely normal conditions. Additional sources were checked, which showed information consistent with the CEC. Due to the difficulty of predicting hydrologic conditions, and given the above information, it is reasonable to assume normal hydrologic conditions for the 2004 Revenue Requirement Period.

### **Sales of Excess Energy Assumptions**

As with any retail provider of energy, the Department and IOUs together, from time to time, purchase more energy than is needed to serve their retail customers. In general, these additional purchases result from differences between projected and actual IOU load. This excess energy is sold in wholesale markets. On occasion, the price obtained will be less than the price paid. However, these minimal losses are an expected incident of appropriate portfolio management, in that losses on sales from overprocurement are on average less than the costs associated with spot market purchases when there has been an underprocurement. The income from such sales is used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers.

On September 19, 2002, the Commission issued Decision 02-09-053, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-five PLTPCs to a specific IOU. Decision 02-09-053 also determined that income from the sale of excess energy (off-system sales) would be shared on a pro-rata basis between the Department and the IOUs.

The Department's share of revenue from the sale of excess energy from the PLTPCs is provided in Table D-11 below.

**TABLE D-11  
SALE OF EXCESS ENERGY**

	<b>Excess Energy Sales Volume (GWh)</b>	<b>Excess Energy Sales Revenue (Millions of Dollars)</b>	<b>Weighted Average Price (\$/MWh)</b>
Q1 – 2004	1,398	37	27
Q2 – 2004	1,104	26	23
Q3 – 2004	1,013	29	29
Q4 – 2004	1,662	53	32
Total	5,176	144	28

### **Extraordinary Costs**

In 2004, the Department has identified, as a separate line item, cash collateral provided in connection with gas purchases, previously included within Power Costs. The Department analyzed the NYMEX margin requirements to secure futures on the highest seven months of fuels requirements. Margin requirements of the NYMEX exchange are listed by the exchange. The margins are exchange requirements based upon a fixed price per contract. In order to come up with a total margin cost, anticipated fuel volumes from June through December 2004 were utilized. These anticipated fuel volumes are determined through the use of the production simulation analysis that underlies this 2004 Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from

June through December 2004 would be \$71 million. This amount is comparable to the 2003 collateral requirement of \$54 million.

### Contract Assumptions

The Department, in cooperation with representatives of the Attorney General's office, the Commission's staff, staff of the Electricity Oversight Board, and representatives of the Governor's staff held multiple sessions with several counterparties to the Department's long-term contracts in efforts to modify terms and conditions of those contracts. As a result of these efforts, only five of the remaining contracts have yet to be renegotiated from their original terms.

Table D-12 provides a listing of all of the original long-term energy contracts and describes the term and capacity associated with each contract and the IOU to which the contract has been allocated. The long term contracts could lead to the construction of approximately 6700 MW is new generating capacity. The recently executed El Paso settlement is included in Table D-12. Detailed contract terms can be found on the CERS website, <http://cers.water.ca.gov>.

**TABLE D-12  
LONG TERM CONTRACT LISTING**

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
<b>Allegheny Energy Supply Company, LLC</b>	3/23/2001 Renegotiated 6/10/03	3/23/2001	3/31/2001	150	Expired
"	" "	4/1/2001	6/30/2001	750	Expired
"	" "	7/1/2001	9/30/2001	250	Expired
"	" "	10/1/2001	12/31/2003	250	SCE
"	" "	1/1/2004	12/31/2004	500	SCE
"	" "	1/1/2005	12/31/2005	750	SCE
"	" "	1/1/2006	12/31/2011	800	SCE
"	4/20/2001	1/1/2003	12/31/2003	150	PG&E
<b>Alliance Colton LLC</b>	4/23/2001 Renegotiated 9/19/02	8/1/2001 on	12/31/2010	80	SCE
<b>BPA</b>	2/16/2001	2/16/2001	12/31/2001	TBD	Expired
"	2/9/2001	2/13/2001	4/30/2002	18	Expired
<b>CalPeak Power--Midway LLC (moving to a new site)</b>	8/14/2001 Renegotiated on 5/2/02 TERMINATED 6/13/03			48	N/A
<b>CalPeak Power--Panoche LLC</b>	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	48	PG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
CalPeak Power-- Vaca Dixon LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	48	PG&E
CalPeak Power-- El Cajon LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	48	SDG&E
CalPeak Power-- Border LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	48	SDG&E
CalPeak Power-- Enterprise LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	48	SDG&E
CalPeak Power-- Mission LLC	8/14/2001 TERMINATED 5/2/02	on		Was 48	N/A
Calpine Energy Services, L.P. (Firm)	2/6/2001 Renegotiated 4/22/02	10/1/2001 on	12/31/2001	200	Expired
"	"	1/1/2002	12/31/2002	350	Expired
"	"	1/1/2003	12/31/2003	600	PG&E
"	"	1/1/2004	12/31/2009	1000	PG&E
"	Added by Renegotiation	4/22/02 5/1/2002	5/31/2002	200	Expired
"	"	6/1/2002	6/30/2002	50	Expired
"	"	7/1/2002	5/31/2003	650	PG&E
"	"	6/1/2003	12/31/2003	400	PG&E
"	"	5/1/2002	12/31/2003	400	PG&E
Calpine Energy Services, L.P. (Long Term Commodity Sale)	2/26/2001 Renegotiated 4/22/02	7/1/2001 on	12/31/2001	200	Expired
"	"	1/1/2002	6/30/2002	200	Expired
"	"	7/1/2002	12/31/2009	1000	PG&E
"	Added by Renegotiation	4/22/02 5/1/2002	6/30/2002	800	Expired
"	"	6/1/2002	12/31/2002	500	Expired
"	"	6/1/2003	9/30/2003	500	PG&E
"	"	5/1/2002	12/31/2003	400	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated 4/22/02	8/1/2001 on	11/30/2001	90	Expired
"	"	12/1/2001	1/31/2002	135	Expired
"	"	6/1/2002	7/31/2002	450	Expired
"	"	8/1/2002	7/31/2011	495	PG&E
Calpine Energy Services, L.P. (North San Jose Project)	6/11/2001 Renegotiated 4/22/02	3/6/2003 on	3/04	180	PG&E
"	"	Upon COD, TBD	3/6/2006	225	PG&E

Counter-Party	Date Executed		Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Capitol Power, Inc.	8/23/2001 Renegotiated on 3/8/02; TERMINATED on 11/15/02				Was 15	Expired
Clearwood Electric Company, LLC	6/22/2001 Renegotiated 11/20/02	on	Upon COD, est 7/05	12/31/2012	25 to 30	PG&E
Constellation Power Source, Inc.	3/9/2001 Renegotiated 4/22/02	on	4/1/2001	6/30/2003	200	SCE
"	Added by Renegotiation	4/22/02	5/1/2002	10/31/2002	400	Expired
"	"		5/1/2003	10/31/2003	400	PG&E
Coral Power, LLC	5/24/2001		5/24/2001	6/30/2001	100	Expired
"	"		7/1/2001	7/31/2001	150	Expired
"	"		8/1/2001	8/31/2001	250	Expired
"	"		9/1/2001	9/30/2001	325	Expired
"	"		10/1/2001	6/30/2002	200	Expired
"	"		7/1/2002	6/30/2003	300	PG&E
"	"		7/1/2003	12/31/2003	400	PG&E
"	"		1/1/2004	12/31/2005	400	PG&E
"	"		1/1/2006	6/30/2010	400	PG&E
"	"		7/1/2010	6/30/2012	100	PG&E
"	"		7/1/2002	6/30/2012	100	PG&E
"	"		7/1/2003	6/30/2012	175	PG&E
"	"		7/1/2004	6/30/2012	175	PG&E
Dynegy Power Marketing, Inc.	3/2/2001		3/6/2001	12/31/2001	1000	Expired
"	"		3/6/2001	12/31/2001	200 (off-pk only)	Expired
"	"		1/1/2002	12/31/2004	500-1500	SCE
"	"		1/1/2002	12/31/2004	200-1500 (off pk only)	SCE
"	"		1/1/2002	12/31/2004	200	SCE
"	"		1/1/2002	12/31/2004	600	SCE
El Paso Merchant Energy <sup>16</sup>	2/13/2001 Renegotiated 6/24/2003	on	2/9/2001	12/31/2005	50	SCE
"	"		"	"	50	PG&E

<sup>16</sup> The renegotiated terms are not included in the 2004 Revenue Requirement due to outstanding conditions precedent on the settlement. The renegotiated terms will be included in subsequent PROSYM Runs upon settlement closing.

Counter-Party	Date Executed		Delivery Start Date	Delivery End Date	Capacity MW	Allocated
GWF Energy LLC	5/11/2001 Renegotiated 8/22/02	on	9/6/2001	12/31/2011	88	PG&E
"	"		7/1/2002	12/31/2011	88	PG&E
"	"		6/01/03	10/31/2012	164	PG&E
High Desert Power Project	3/9/2001 Renegotiated 4/22/02	on	4/22/2003	3/31/2011	Up to 840	SCE
Imperial Valley Resource Recovery Company, LLC ("Primary Power")	3/13/2001		6/1/2001	12/31/2003	16	SDG&E
InterCom	8/24/2001		1/1/2002	8/31/2003	200	PG&E
Mirant Americas Energy Marketing LP	5/22/2001		6/1/2001	12/31/2002	500	Expired
Morgan Stanley Capital Group	2/14/2001 Renegotiated 7/10/03	on	2/15/2001	06/30/2003	50	SDG&E
"	"		7/1/2003	12/31/2003	40	SDG&E
"	"		1/1/2004	12/31/2005	35	SDG&E
PacifiCorp	7/6/2001		7/29/2001	6/30/2002	150	Expired
"	"		7/1/2002	12/31/2002	200	Expired
"	"		1/1/2003	6/30/2004	200	PG&E
"	"		7/1/2004	6/30/2011	300	PG&E
Pinnacle West	5/3/2001		5/3/2001	5/31/2001	100 (off pk only)	Expired
"	"		6/1/2001	6/30/2001	100 (off pk only)	Expired
"	"		7/1/2001	9/30/2001	100 (off pk only)	Expired
"	"		6/1/2001	9/29/2001	Varies (40 to 125 MW)	Expired
PG&E Energy Trading	5/31/2001 Renegotiated 10/1/02	on	10/1/2001	9/30/2011	66.6	SCE
PX Block Forward	Seized		4/1/2001	6/30/2001	275 (aggregated)	Expired
"	Seized		7/1/2001	9/30/2001	500 (aggregated)	Expired

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	Seized	10/1/2001	12/31/2001	125 (aggregated)	Expired
"	Seized	4/1/2001	6/30/2001	500 (aggregated)	Expired
"	Seized	7/1/2001	9/30/2001	925 (aggregated)	Expired
"	Seized	10/1/2001	12/31/2001	450 (aggregated)	Expired
<b>Santa Cruz County</b>	9/13/2001 Renegotiated 12/19/02	on Upon COD, Est 12/31/03	6/30/2007	2 to 3	PG&E
<b>Sempra Energy Resources</b>	5/4/2001	6/1/2001	9/30/2001	250	Expired
"	"	4/1/2002	9/30/2002	150	Expired
"	"	"	"	300	Expired
"	"	10/1/2002	5/31/2003	220	SCE
"	"	6/1/2003	12/31/2003	1000	SCE
"	"	1/1/2004	9/30/2011	1200; drops to 800 in Mar-May of 2004-2007	SCE
"	"	6/1/2003	12/31/2003	350	SCE
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	SCE
<b>Soledad Energy LLC</b>	4/28/2001; terminated on 3/27/02; Revision Executed on 6/27/02	9/09/2002	10/31/2006	13	PG&E
<b>Sunrise Power Company, LLC</b>	6/25/2001 Renegotiated 12/31/02	on 7/16/2001	2/28/2003	325	SDG&E
"	"	6/01/03	6/30/2012	560	SDG&E

Counter-Party	Date Executed		Delivery Start Date	Delivery End Date	Capacity MW	Allocated
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated 12/17/02	on	8/20/2001	10/31/2011	21.3	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated 12/17/02	on	12/27/2001	10/31/2011	46.5	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated 12/17/02	on	12/14/2001	10/31/2011	49.9	PG&E
Whitewater Energy Corp. (Cabazon Project)	7/12/2001 Renegotiated 4/24/02	on	8/31/2002	12/31/2013	43	SDG&E
Whitewater Energy Corp. (Whitewater Hill Project)	7/12/2001 Renegotiated 4/24/02	on	8/31/02 (partial)	12/31/2013	65	SDG&E
Williams Energy Marketing & Trading	2/16/2001 Renegotiated 11/11/02	on	6/1/2001	9/30/2001	35	Expired
"	"		10/1/2001	11/11/2002	40	Expired
"	"		1/1/2003	6/30/2003	40	SDG&E
"	"		7/1/2003	12/31/2007	200	SDG&E
"	"		4/1/2001	9/30/2001	175	Expired
"	"		10/1/2001	11/11/2002	200	Expired
"	"		1/1/2003	6/30/2003	175	SDG&E
"	"		7/1/2003	12/31/2005	450	SDG&E
"	"		1/1/2006	12/31/2006	450	SDG&E
"	"		1/1/2007	12/31/2007	450	SDG&E
"	"		1/1/2008	12/31/2008	275	SDG&E
"	"		1/1/2009	12/31/2009	275	SDG&E
"	"		1/1/2010	12/31/2010	275	SDG&E
"	"		6/1/2001	9/30/2001	140	Expired
"	"		10/1/2001	11/11/2002	160	Expired
"	"		7/1/2003	12/31/2010	50	SDG&E
"	Added by 11/11/2002 Renegotiation		1/1/2003	6/30/2003	430	SDG&E
"	"		7/1/2003	12/31/2007	1175	SDG&E
"	"		1/1/2008	12/31/2010	1045	SDG&E

### Contract Management and Disposition Alternatives

The power charge component of the revenue requirement is directly related to the costs of power supplied under the contracts. In considering changes to the contracts to modify its revenue requirements, the Department can (1) continue to use its contracts in their present

form, (2) seek to modify the contracts through bilateral renegotiation with its counterparties, or (3) terminate the contracts.

As described in Table D-12 of this Determination, the Department has renegotiated 23 of its original contracts entered into in 2001 and has terminated four additional contracts for cause. As shown on Table D-12 thirteen of those contracts were renegotiated since submittal of the Department's 2003 revenue requirement filing to the Commission in August of 2002, and two of the contracts were terminated for cause in that intervening period. The Department has continued efforts to renegotiate additional contracts. The Department continues to monitor its contracts and determine if there are opportunities for bilateral renegotiation, which could lead to more favorable power supply terms and costs.

Theoretically, the Department could terminate one or more of its contracts. The terms of each of the Department's contracts provide that if the contract is terminated for reasons other than breach or default by the power supplying counterparty to the contract, the Department is obligated to pay the entire remaining estimated value of the contract. Any such termination other than for an uncured default or breach by the seller would likely increase the revenue requirement due to timing implications of the payments to the counterparty. In addition, energy no longer supplied DWR would need to be replaced by the investor-owned utilities in either the short-term market or new long-term contracts from other suppliers. For this reason, under present market conditions and terms of the contracts, the Department does not believe that termination of any of the contracts would result in a net savings in the revenue requirement or overall rate payer costs.

### **Administrative and General Costs**

The Department's administrative and general costs of \$59 million included in Power Charges consist of \$55 million included in the Department's appropriated budget plus \$4 million for consulting services for development and monitoring of the revenue requirements, and financial advisory and related consulting services for managing the \$11 billion debt portfolio and related reserves.

The 2003-2004 State Budget has \$55 million appropriated for the Department's power supply program. This includes funds for labor and benefits, professional service costs, including costs for litigation, and \$28 million for pro-rata charges for services provided to the Power Supply program by other State agencies. The pro-rata charge includes \$14 million that is retroactive to the 2001-2002 fiscal year and \$14 million for the 2003-2004 fiscal year.

### **Financing Related Assumptions**

In October and November 2002, the Department issued \$11.263 billion of Power Supply Revenue Bonds. The primary uses of net Bond proceeds were to (a) repay the then-outstanding balance of the \$4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately \$6.1 billion advanced to the

Department for 2001 power purchases and interest that had accrued on the General Fund advances, and (c) fund reserves required to complete the bond financing.

The details of the Bond financing structure were made public in connection with the Department's 2003 Revenue Requirement filing and are described in the Bond Indentures and Supplemental Bond Indentures for each series of Bonds.

For purposes of calculating the interest earnings on all account balances, the Department assumes a 2.0 percent earnings rate for the 2004 Revenue Requirement Period. Although the recent actual earnings rate has been slightly lower than 2.0 percent per annum, the Department anticipates the opportunity to solicit and make longer term and higher interest rate investment arrangements for the Debt Service Reserve Account.

The Department projects that the amount of Bond Charge Revenues required for the 2004 Revenue Requirement Period will be \$873 million.

### **Accounts and Flow of Funds Under the Bond Indenture**

The terms agreed to in the Rate Agreement and Summary of Material Terms with all applicable addenda are reflected in the Bond Indenture. The following is a description of the funds and accounts that are required as part of the Bond program.

Revenues are held in and accounted for in the Electric Power Fund established under AB1X. The Bond Indenture established two sets of accounts for Revenues within the Electric Power Fund. In the following description of accounts and the flow of funds, capitalized terms refer to terms that are further defined in the Indenture.

One set of accounts is primarily for the deposit of Power Charge Revenues and the payment of Operating Expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the "Power Charge Accounts"):

- The Operating Account,
- The Priority Contract Account,
- The Operating Reserve Account, and
- The Administrative Cost Account.

The other set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the "Bond Charge Accounts"):

- The Bond Charge Collection Account,
- The Bond Charge Payment Account, and
- The Debt Service Reserve Account.

The Bond Indenture requires all Bond Charge Revenues to be deposited in the Bond Charge Collection Account and all Power Charge Revenues and other Revenues (other than Bond Charge Revenues) to be deposited in the Operating Account.

### **Operating Account**

The Department has covenanted to include in its revenue requirements amounts sufficient to cause a Minimum Operating Expense Available Balance ("MOEAB") to be on deposit in the Operating Account. The MOEAB is to be calculated by the Department at the time of each determination of a revenue requirement and for 2003 and successive calendar years is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes (i.e., "stress cases").

Responsibility for the procurement of the residual net short was transitioned to the IOUs effective the end of 2002.

For the purposes of this 2004 Proposed Determination, the MOEAB is determined by the Department to be \$285 million.

### **Priority Contract Account**

The Priority Contract Account is used to pay the costs the Department incurs under its Priority Long Term Power Contracts, which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs. On or before the fifth Business Day of each month, the Department is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

For the 2004 Revenue Requirement Period it is projected that the Priority Contract Account will have sufficient funds available from the Operating Account, and that no transfer from Bond Charge Collection Account to the Priority Contract Account will be required.

### **Operating Reserve Account**

The Operating Reserve Account Requirement ("ORAR") is to be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) either (i) 18 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is procuring all or a portion of the residual net short and which commences prior to 2006, or (ii) 12 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is not procuring all or a portion of the residual net short or which commences after 2005, provided, however, that solely for purposes of (b) above, for Revenue Requirement Periods commencing after 2003, the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent

the Department no longer is financially responsible for any particular Power Supply Contract. All projections will be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., “stress cases”).

With the successful transition of the residual net short procurement responsibility to the IOUs at the end of 2002, the ORAR is sized as the maximum seven-month difference between operating revenues and expenses as calculated under “stress” operating conditions (later described in the “Sensitivity Analysis” portion of Section D). The ORAR for the 2004 Revenue Requirement Period is determined by the Department to be \$579 million.

### **Bond Charge Collection Account**

All Bond Charge revenues will be deposited in the Bond Charge Collection Account. Subject to the prior claim on revenues in the Bond Charge Collection Account for the payment of costs under the Long-Term Priority Contracts, on or before the last Business Day of each month, the Department is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds and all other Bond Related Costs) estimated to accrue or to be due and payable during the next succeeding three calendar months.

The minimum balance to be maintained from time to time within the Bond Charge Collection Account is determined to be an amount equal to one month’s required deposit to the Bond Charge Payment Account. As required by the Bond Indenture, the Department assumes interest costs on unhedged Variable Rate Bonds during the 2004 Revenue Requirement Period at 4.0 percent for the purpose of calculating required deposits to the Bond Charge Payment Account. For the 2004 Revenue Requirement Period, the minimum account balance amount ranges from \$75 to \$78 million.

### **Bond Charge Payment Account**

The Bond Charge Payment Account is calculated as an amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month. The Department assumes interest costs on unhedged Variable Rate Bonds during the 2004 Revenue Requirement Period at 4.0 percent for the purpose of calculating debt service accruals in the Bond Charge Payment Account. For the 2004 Revenue Requirement Period, the minimum account balance amount ranges from \$253 to \$656 million.

### **Debt Service Reserve Account**

The “Debt Service Reserve Requirement” is an amount equal to maximum aggregate annual debt service on all outstanding Bonds, determined in accordance with the Bond Indenture. The Debt Service Reserve Account is required by the Bond Indenture to be funded in the amount of the Debt Service Reserve Requirement, initially with proceeds from the sale of the Bonds (or Alternate Debt Service Reserve Account Deposits referred to below, or a combination of both) and subsequently maintained and replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues.

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been outstanding, or (b) 4.0 percent. For the 2004 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.0 percent.

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations. The Department is not currently assuming the use of Alternate Debt Service Reserve Account Deposits.

For the 2004 Revenue Requirement Period, the Debt Service Reserve Requirement is determined to be \$927 million.

### **Sensitivity Analysis**

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the Commission no less than once each year, thereby ensuring that Bond Charges and Power Charges are adequate to meet financial obligations associated with the Bonds and the power supply program. From the date the Department first initiates a revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, file and initiate the Commission process regarding the new revenue requirement and allocation of costs among customers, and finally begin receiving the modified level of revenue. In order to ensure its ability to meet its financial obligations during this seven month lag period, the Department must maintain reserves that are adequate to meet normal anticipated expenses, unexpected variations in these expenses, and/or reductions in revenue receipts resulting from factors beyond the Department's control. The determination of reserve levels is made by the Department considering such factors as the potential variations in revenue receipts and power supply program expenses, changes in key variables affecting customer energy requirements, URG production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of cash flow projections based on changes in certain key expense and operating assumptions ("Stress Cases"). The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, a market simulation was performed to generate revised net short requirements and associated

power supply costs. These revised forecasts were used to generate revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the “Base Case”).

The Department comprehensively analyzed two Stress Cases in this Determination.

#### **Case 1**

This Stress Case focuses on decreased Bond Charge and Power Charge revenues resulting from lower sales to its customers, and increased costs of providing energy under existing contracts.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the Base Case forecast<sup>17</sup>. Lower customer sales by the Department are driven primarily by a decrease in the net short, which can occur as a result of increased URG and/or decreased customer load. On occasion, for reasons completely beyond the Department’s control, the actual loads of the utilities’ retail customers would be significantly lower than levels that had been forecast by the respective utilities the day before, and at times hours before. In these circumstances, the Department would either dispatch its dispatchable power supply resources as scheduling coordinator, or would purchase energy in the spot market to meet the forecast need, only to find that loads were significantly lower, resulting in excess energy. This excess resulted in requirements to sell energy off-system, often in the “real-time” market, at prices which would then be depressed, in part due to the very purchases the Department made in response to the forecasts provided by the utilities. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 115% of normal for 2004 and 2005.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2004 and 2005, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2004 and 2005 by 3% for June and July, and by 5% for August and September. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of 4% in 2004 and 2% in 2005. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department’s required recovery cost per MWh.

#### **Case 2**

This Stress Case focuses on increased costs of providing energy under existing contracts, and considers increased contract dispatch due to higher customer load and reduced URG.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the Base Case forecast. Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by

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<sup>17</sup> Based on Gas Daily Monthly Index Prices, monthly gas prices have more than doubled year over year 10 times from 1999 through 2003.

assuming California and Pacific Northwest hydroelectric production at 75% of normal in 2004 and 2005. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit in the first quarter of 2004.

Higher loads are estimated in this case by assuming load growth rates that are 1.4% of total load higher than those assumed in the Base Case in 2004 and 1.3% higher in 2005. It is assumed that this growth occurs as a result of an accelerated economic recovery in California and decreases in the expected amount of non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2004 and 2005. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2004 and 2005 by 3.2%, 3.6%, 5.4%, and 4.6% for June, July, August, and September respectively.

## **E. Key Uncertainties In The Revenue Requirement Determination**

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2004 period after this initial determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California.

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs
  - a. Legal challenges to DWR's administrative process;
  - b. Administrative and legal challenges to DWR's revenue requirements;
  - c. Litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement;
  - d. Application and enforcement of CPUC's Bond Charge rate covenant; and
  - e. DWR's assessment of these risks.
2. Collection of Bond Charges and Power Charges
3. Bankruptcy risks
  - a. Uncertainty as to outcome of PG&E bankruptcy;
  - b. Potential rejection of Servicing Arrangements or other disruption of servicing arrangements; and
  - c. Potential impact of PG&E bankruptcy proceedings on PG&E Servicing Order.
4. Certain risks associated with DWR's Power Supply Program
  - a. Priority Long-Term Power Contracts
    - i. Impact of renegotiated contracts
    - ii. Off-System sales volume and price variability
    - iii. Failure or inability of the suppliers to perform as promised including but not limited to any failure to add new capacity to the grid;

- b. Transition risks; and
  - c. DWR administrative expenses appropriation by State Legislature
- 5. Potential increases in overall electric rates
  - a. Changes in general economic conditions;
  - b. Energy market-driven increases in wholesale power costs;
  - c. Fuel costs;
  - d. Hydro conditions and availability;
  - e. Market manipulation;
  - f. “Block Forward Contracts” consolidated actions;
  - g. Action requiring DWR to pay for power ordered for PG&E and SCE;
  - h. Actions affecting retail rates; and
  - i. Impact of these factors
- 6. Potential decrease in DWR customer base
  - a. Direct Access; and
  - b. Load departing IOU service
- 7. Potential variance in dispatch of DWR contracts
  - a. Actual vs. Forecast Load Variance; and
  - b. Lack of dispatch coordination between IOUs and DWR
- 8. Uncertainties relating to electric industry and markets
  - a. Electric Transmission Constraints; and
  - b. Gas Transmission Constraints
- 9. Uncertainties relating to government action
  - a. California Emergency Services Act;
  - b. Possible State Legislation or action;
  - c. Recent State Legislation; and
  - d. Possible Federal Legislation or action.

## **F. Just and Reasonable Determination**

This section explains the Department’s reasons for determining that this Determination is just and reasonable, and the process leading to the rendering of this determination.<sup>18</sup>

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<sup>18</sup> The Department’s obligations in relation to just and reasonable determinations remain subject to actions pending in the Sacramento Superior Court and the Third District Court of Appeal for the State of California. A controversy exists between Pacific Gas and Electric Company and the Department over both the necessity and the required scope of any review of the Department’s costs under Division 27 or the Water Code. Neither the inclusion nor the contents of this just and reasonable determination in this Revenue Requirement constitute an admission on the Department’s part as to the necessity or scope thereof.

### **The August 16, 2002 Determination**

The August 16, 2002 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2003 as determined therein was just and reasonable. Included in that material was background information on the situation California was facing, the Legislative actions taken and the gubernatorial direction leading to the Department's role and participation. Also included was a discussion of the meaning of just and reasonable, and a discussion of the California Administrative Procedure Act. In finding the August 16, 2002 Determination to be Just and Reasonable, the Department discussed the long-term power purchase contracts including the existing market conditions, the portfolio planning process, the procurement activities and the negotiating environment and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this 2004 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2004 Revenue Requirement proceeding. For further information please refer to Section I.

### **The 2003 Supplemental Determination**

Subsequent to August 16, 2002, new information became available to the Department. Such new information either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2003 Supplemental Determination. The just and reasonable determination in the 2003 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2004 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2004 Revenue Requirement proceeding. For further information please refer to Section I.

### **The 2004 Determination**

#### **Development of the Determination**

Under the terms of the Rate Agreement between the Department and the Commission, and the terms of the Bond Trust Indenture, the Department is required to submit a new Revenue Requirement annually.

In April 2004, the Department requested each of the IOUs provide certain projected information including, but not limited to, load data, Direct Access Departing Load information, retained generation including bilateral contracts, QF information and owned generation. Also requested was a listing of the DWR Contracts administered by the IOU with certain operating data and information pertaining to off-system sales.

The information obtained from the IOUs, much of which is considered by each individual IOU as confidential and provided under a non-disclosure agreement, was compared with other relevant data such as forecasts prepared by the California Energy Commission (CEC) and the Western Electricity Coordinating Council (WECC). The Department considered other important criteria such as Commission Decisions and Bond Trust Indenture requirements. The resulting data was incorporated into the PROSYM simulation model and

the Financial Model, and became a meaningful part of the projections leading to this Determination.

The long-term contracts contained in this Determination were reviewed extensively in the August 16, 2002 Determination, with updates for renegotiation efforts reviewed in the Supplemental Determination of July 1, 2003. This Determination includes and reflects the positive results of the Departments continuing efforts to renegotiate contracts. This inclusion is limited to efforts that have been completed and are not subject to ongoing regulatory review, with final decisions pending at a future date. A discussion of the assumptions used in the development of this Determination is found in Section D.

### **Public Process**

On July 17, 2003, the Department Noticed and published its Proposed Determination of Revenue Requirements for 2004, for public review and comment. On August 6, 2003, the Department issued a Notice of Significant Additional Material, and provided additional material relied upon, and extended the period for review and comment. The Department has provided interested parties PROSYM output data and Financial Model data, subject to applicable nondisclosure requirements.

In an effort to assist interested parties in the review and understanding of the PROSYM and Financial Model underlying the Proposed Determination, the Department conducted conference calls, Webex presentations and responded to questions from interested parties.

On August 14, 2003, the Department received comments from SCE, SDG&E, and PG&E. No other person provided comments. The Department has reviewed and considered all comments prior to making this Determination. The Departments response to the comments is found in Section H. The comments are included in the administrative record and are referenced in Section I

### **Just and Reasonable Determination**

The Department reviewed and considered each comment received. In addition, the Department received Commission Decision 03-09-018, allocating the 2003 Supplemental Determination of Revenue Requirements. After review of all comments and analysis of Decision 03-09-018, the Department has made the following changes in the 2004 Revenue Requirement:

- (1) Modeled Decision 03-09-018 and updated the Financial Model with actual results through June 2003, resulting in a projected ending 2003 aggregate balance in the Power Charge Accounts of \$1.386 billion, \$29 million higher than the balance projected in the 2003 Supplemental Filing.

- (2) Corrected the net debt service inputs reported on the “bonds” tab of the Financial Model. The corrected net debt service is reflected below;

Period	Actual Net Debt
Dec-02	4,582,265
Jan-03	14,916,221
Feb-03	13,307,900
Mar-03	9,966,705
Apr-03	11,686,395
May-03	182,056,707
Jun-03	9,878,613

- (3) Removed from Department Contract Costs the following PG&E Interim Procurement Contracts.

Station	Allocation	ContractName
IP_Wheelab SH4	PG&E	Wheelabrator
IP_CalpGeys 20	PG&E	Calpine Geysers-20
IP_CalpGeys 13	PG&E	Calpine Geysers-13
IP_Bvalley	PG&E	Big Valley

- (4) Added the results of the re-negotiated Morgan Stanley Contract (MD DWRS 1B B)
- (5) Reflected the termination of the Calpeak NP A-Lodi, formerly Midway

After assessing all comments, the administrative record, AB1X and the Regulations, the Department has determined this Determination of Revenue Requirements for the 2004 period, is just and reasonable.<sup>19</sup>

## G. Market Simulation

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, supply and price of natural gas and coal, power transfer capability of major interties, operating costs, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. The Department analyzed the fundamental drivers underlying the electricity market by generating computer simulations of market activity throughout the Western Electricity Coordinating Council (“WECC”) region. PROSYM price forecasting and market simulation tool was used.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and

<sup>19</sup> The nature and requirement of any just and reasonable determination or review under Water Code section 80100 is currently the subject of litigation, and the DWR by making this determination does not waive the right to contend that such a determination or review is not required, or that any requirement of such a determination or review is limited in scope.

revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this revenue requirement determination, the demand and energy forecasts used were those that have been described earlier.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only "single-price" market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment. In the near-term, the use of a single-price mechanism for the residual net short produces a reasonable assessment of market prices.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

$$\text{Market-Clearing Price} = \text{Incremental Production Cost} + \text{Start Cost} + \text{No-Load Cost} + \text{Price Markup}$$

Where:

- Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;
- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;
- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and,
- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

- 1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.
- 2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources

such as older steam turbine units having relatively high production costs are assigned this bid strategy.

- 3) **Peak Period Bidding:** Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in the analysis underlying this determination. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

**CALIFORNIA AND WECC BID STRATEGY ASSESSMENT  
(PERCENT OF SUPPLY)**

	<u>Incremental</u>	<u>Price Markup</u>	<u>Peak Period Bidding</u>	<u>Total</u>
California.....	68%	28%	4%	100%
Non-California.....	80%	14%	6%	100%
Total WECC .....	75%	20%	5%	100%

### **FERC Price Mitigation**

On July 17, 2002, FERC issued an order related to CAISO market design initiatives that established a hard price cap of \$250 per MWh, effective October 1, 2002. For purposes of this Determination, the price cap is assumed to remain in effect throughout the 2004 Revenue Requirement Period.

### **WECC Regional Market Definitions**

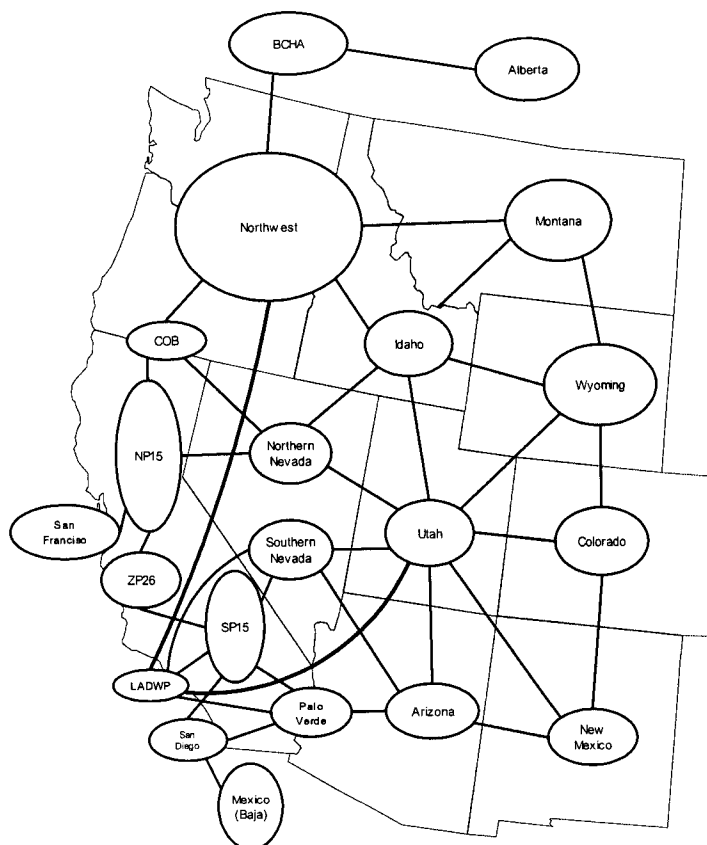
WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation took into account economic import and export possibilities and set the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.

### Simulation of New Resource Additions

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.



To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the 2004 Revenue Requirement Period.

## GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh) .....	11,000	7,100
Fixed O&M (\$/kW-year) .....	3.15	10.50
Variable O&M (\$/MWh) .....	4.20	2.10
Forced Outage Rate (%) .....	0.00	2.00
Maintenance Outage Rate (%) .....	4.00	4.00
Financing Term (Years) .....	15	15
Interest Rate (%) .....	8.00	8.00
Return on Equity (%) <sup>1</sup> .....	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.

<sup>1</sup> After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, “generic” new generating units are assumed to be added to the resource mix.

### Long-Term Power Contracts

The Department’s contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers’ perspective) as part of a complete resource mix that includes the utility retained generation, the Department’s contracts, and residual net short purchases. The Department’s Long-Term Power Contracts are available for viewing at the Department’s web site: <http://www.cers.water.ca.gov>.

### Potential Risks to Economically Efficient Dispatch

#### Operational and Utility Coordination Influences on Revenue Requirement

Operational and coordination issues between the Department and the three utilities influence the dispatch of Department contracts, and have historically influenced the residual net short purchases by the Department (when the Department had such responsibility from January 2001 through December 2002). Variances between forecast energy needs by the utilities and the actual real-time demand for energy affects the volume of Department contract energy that must be sold off-system. Similarly, the degree of coordination between the Department and the utilities for dispatch of utility retained generation and Department contract dispatch has influenced the volume of off-system sales. These factors, which are outside the control of the Department, affect the net sales volume and size of the Department’s revenue requirement.

### **CAISO Locational Marginal Price and Congestion Revenue Rights Proposals**

The California ISO has authorized its staff to develop detailed plans as part of its Market Design 2002 (“MD02”) to create a structure that establishes locational marginal prices (“LMP”) at many different nodes on the CAISO grid. In addition, the CAISO has adopted plans to create Congestion Revenue Rights (“CRR”) which could have the effect of requiring the utilities to purchase CRRs to assure the delivery of energy from certain of the Department’s long-term energy supply contracts or else risk the possibility of failure to deliver either must-take energy or energy which would otherwise be economically dispatched from the Department’s contracts.

No such structure existed at the time the Department entered into the long-term contracts, and the Department is unaware of any analysis by the CAISO or others as to what effect LMP and CRR could have on the delivery of energy from the Department’s contracts. To the extent that CRRs need to be purchased to assure delivery of energy under the Department’s contracts, such costs would increase the Department’s revenue requirement beyond the levels that would otherwise exist. To the extent that others purchase CRRs and such purchases preclude some portion of the Department’s energy from being delivered, then the Department assumes that its average cost per MWH of energy will increase and the utilities will need to replace that energy which is not delivered due to this proposed market structure. The extent to which this structure could increase the Department’s revenue requirement and the three utilities’ separate revenue requirement for the replacement energy they may need to acquire is unknown at this time.

At present, it is the Department’s understanding that the CAISO does not intend to implement the LMP and CRR provisions of MD02 until 2005 at the earliest. As a result, the Department does not anticipate the MD02 implementation to affect the Department’s 2004 revenue requirement. The Department intends to monitor the CAISO’s process for evaluation and implementation of LMP and CRR to better assess and seek to quantify the possible effects of these energy market structural changes.

## Other Assumptions

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2004 through December 2004.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Determination.
Load Profiles	SCE and SDG&E load profiles were provided by the IOUs. The PG&E load shape was based on the composite hourly load profile for the 1993-1998 period contained in PROSYM. The PG&E load profiles were derived from hourly Edison Electric Institute load data files from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	<ul style="list-style-type: none"> <li>• Multi-segment incremental heat rate curves.</li> <li>• Fixed and variable O&amp;M costs.</li> <li>• Scheduled outages based on annual maintenance cycles.</li> <li>• Random forced outages based on unit-forced outage rates.</li> </ul>
Contracts	<ul style="list-style-type: none"> <li>• Known firm purchase/sales reported in the WECC Form OE-411 filing.</li> <li>• Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity.</li> <li>• Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.</li> </ul>
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

## **H. Comments Received on the Proposed Determination and the Department Response**

On August 14, 2003, SCE, SDG&E, and PG&E provided comments on the Proposed Determination published on July 18, 2003, and on the Significant Additional Material, published August 6, 2003.

The Department has reviewed and considered all comments. The comments are summarized below, and the Department's response is also provided. The comments provided by each of the IOUs and additional materials referenced and provided by PG&E have been made part of the administrative record. The complete text of all the comments and the materials referenced and provided by PG&E are available for viewing at the Department's offices.

### **Comments of Southern California Edison on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2004, through December 31, 2004**

#### **Comment 1: Sufficient information not provided**

DWR has presented an integrated 2004 Proposed Determination that fails to clearly identify and justify the basis for its assumptions and conclusions concerning the utilities' 2004 energy requirements and attendant costs. Consequently, SCE is unable to perform a comprehensive analysis to independently confirm that DWR's 2004 Proposed Determination meets the just and reasonableness requirement of AB1-X.

#### **Response:**

The Department has provided an estimate of all of its Long Term Power Contract costs, administrative and general costs and changes in fund balances. Confidentiality issues concerning disclosure of IOU information to market participants which were raised by SCE during the Department's administrative process have precluded the Department from providing information to SCE pertaining to the energy requirement of each IOU. The Department has made its administrative record in supporting this Determination available for inspection and copying. To date, SCE has not requested to inspect or copy the Department's administrative record.

#### **Comment 2: PG&E peak load DA share and WAPA load inconsistencies**

PG&E's peak load appears too low when compared with historical levels, and its DA share and WAPA load do not appear to be accurately modeled. Footnote 11 on page 18 of the Proposed Determination indicates that PG&E's WAPA requirements have been netted out of PG&E's energy requirements. No such netting is indicated for PG&E's peak load, but the numbers seem to indicate that WAPA load has been netted out. PG&E's peak load is either too low, or the WAPA load amount is excessive. Such omissions and inconsistencies

suggest that some utilities' energy requirements may have been under-estimated or that all utilities are not being treated on a comparable basis.

**Response:**

Although not indicated, PG&E's estimated peak demand in Table D-4 is net of WAPA requirements, similar to Table D-3. PG&E's peak demand was forecast using 2004 annual energy consumption, provided by PG&E to the Department in March 2003, and PG&E's hourly load shape, provided to the Department in September 2002.

**Comment 3: PG&E transitional contract costs assignment**

SCE cannot confirm that PG&E's transitional contract costs have been solely assigned to PG&E. In the 2003 Supplemental Revenue Requirement, PG&E's transitional contract costs appeared to have been improperly included in the overall Revenue Requirement, rather than separately assigned to PG&E. The 2004 Proposed Determination does not address whether this error has been corrected.

**Response:**

The costs of the PG&E transitional contracts were reported in the materials supporting the 2003 Supplemental Revenue Requirement as allocated to PG&E. In its 2003 Supplemental Filing the Department expects to receive its Power Charge on the energy from the PG&E transitional contracts.

In this Determination of Revenue Requirements, the Department has not included the costs of PG&E's transitional contracts.

Material supporting the 2004 revenue requirement includes a CD entitled "Contract Generation PS 42 7-16-03.xls, where a breakout of all the contracts that make up the total DWR portfolio and the contract allocations for SDGE, SCE and PG&E.

**Comment 4: A&G costs are increasing**

A&G costs are estimated at \$59 million, or \$10 million higher than the 2003 Supplemental Revenue Requirement, which itself was \$21 million higher than DWR's A&G costs in the initial 2003 Revenue Requirement Determination. These increases in A&G are largely unexplained and cannot be deemed just or reasonable given the reduced role that DWR should now be performing. DWR should explain why its A&G expenses are expected to increase in 2004 and what steps it is taking to ensure that A&G costs do not continue to escalate.

**Response:**

DWR has significantly decreased its direct expenditures for A&G costs. However, as stated on pages 29 and 30 of the Proposed Revenue Requirement, \$28 million (48%) of the

2004 A&G costs are associated with pro rata charges for services provided to the Power Supply Program by other State agencies. Under the methodology used by the State Department of Finance to develop the Statewide Pro Rata charge, this is the first year that any charge has been allocated to the Power Supply Program. The Statewide Pro Rata methodology includes a true up of costs in the second preceding budget year as well as estimated current budget year costs. Therefore, since the Power Supply Program was not in existence at the time the 2001-2002 allocation was initially determined, the true up charges for 2001-2002 (\$14 million) included in the 2003-2004 budget are substantially the same as the estimate (\$14 million) for the 2003-2004 pro rata charge. Without the pro rata charge, the A&G costs would have been projected to decrease by 37% from 2003.

**Comment 5: Contract energy dispatch low**

SCE's internal forecasts indicate that the DWR contracts will likely be dispatched more frequently than DWR forecasts, resulting in more energy being provided under the contracts than forecasted in the 2004 Proposed Determination.

**Response:**

The 2004 contract dispatch criteria utilized by the Department in the preparation of the 2004 Determination was provided by SCE as described below.

The ProSym inputs for SCE allocated contracts, underlying the 2004 revenue requirement (ProSym 42), was modified based on comments received from SCE for the 2003 Revenue Requirement (ProSym 40) in a letter dated June 23, 2003, signed by J.P. Shotwell, council for SCE.

A comparison of the two ProSym runs indicates that there is a reduction in contract dispatch energy of 147 GWh. A large portion is attributable to three modeled contracts.

The two modeled contracts "Alliance SRA A" and "Alliance SRA B" each had a lower dispatch of 13 GWh. This reduced dispatch can be attributed to an increase in the modeled heat rate for those contracts from 10,240 to 12,932. The minimum up time and minimum down times were also increased which would further reduce its dispatch energy.

The modeled contract "High Desert - Max Load Adjusted" had a lower dispatch of 84 Gwh. This reduced dispatch can be attributed to a reduction in the modeled capacity for that contract from 60 MW to 30-35 MW.

The changes to these three contracts were requested in the aforementioned SCE letter.

With these three modeling alterations taken into account, the reduction in contract dispatch between the two ProSym runs is less than 0.1%. Without taking these modeling alterations into account the entire change in contract dispatch is only 0.5%.

## **Comments of San Diego Gas & Electric Company Regarding Department of Water Resources' July 17, 2003 Proposed determination of 2004 Revenue Requirement**

### **Comment 1: Data Request**

On August 4, 2003 and then on August 8, 2003, SDG&E sent a total of 7 data requests to DWR to clarify certain issues with regard to the Proposed Determination. At this time, SDG&E is not able to fully evaluate the Proposed Determination in that SDG&E has not received responses to all the data requests it submitted to DWR. Until DWR responds to all these data requests, SDG&E will not have the opportunity to fully evaluate and comment on the Proposed Determination.

#### **Response:**

The Department's regulations do not provide for data requests such as the requests submitted by SDG&E. As described elsewhere in this Determination, during the period subsequent to the publication of the Proposed Determination on July 17, 2003, the Department conducted conference calls and Webex presentations with interested persons, including SDG&E, to explain the Proposed Determination and respond to questions and concerns. In addition, as described in applicable notices provided to the public, including SDG&E, the Department has made its administrative record supporting its Proposed Determination of Revenue Requirements for 2004 available for inspection and copying. To date, SDG&E has not requested to inspect or copy the Department's administrative record. However, SDG&E submitted questions requesting additional clarification and explanation as part of its comments. The Department is treating SDG&E's questions as comments on the Proposed Determination. The seven questions are identified below, along with the Department's response.

#### **Question 1**

In the DWR 2004 RR file, SDGE URG PS42 7-16-03.xls, provided to SDG&E, please identify the resources and/or underlying capacity for the following "Stations":

SDGE\_DWRN\_1B

SDGE Bio QF F 1

SDGE Bio QF V 1

SDGE Misc CG Q 1

#### **Response**

The station labeled "SDGE\_DWRN\_1B" represents a bilateral contract. The other units are single QF units or a combination of QF units.

The top section of the following table reflects the PROSYM data provided to SDG&E, in GWh. The bottom section provides the Capacity for the four requested “stations”

Generation (GWh)

ProSym Run 42 Forecasted Data

UtilGroup	Station	Plant	1/1/04	2/1/04	3/1/04	4/1/04	5/1/04	6/1/04	7/1/04	8/1/04	9/1/04	10/1/04	11/1/04	12/1/04
SDGE	San Onofre-SON 2 SDGE	NP	149	134	-	39	149	144	149	149	144	149	144	149
SDGE	San Onofre-SON 3 SDGE	NP	150	136	150	145	150	145	150	150	145	150	146	-
SDGE Inter	Inter-SDGE 1	Inter	-	-	-	-	-	-	-	-	-	-	-	-
SDGE Inter	SDGE_2020 1	Inter	-	-	-	-	-	-	-	-	-	-	-	-
SDGE_Bilateral	SDGE_Bilat 1B B	Transaction	62	54	62	60	-	60	62	62	60	62	60	62
SDGE_Bilateral	SDGE_Bilat_1	Transaction	-	-	-	-	-	-	-	-	-	-	-	-
SDGE_Bilateral	SDGE_Bilat_2	Transaction	-	-	-	-	-	-	-	-	-	-	-	-
SDGE_Bilateral	SDGE_DWRN_1B	Transaction	99	90	99	96	99	96	99	99	96	99	96	99
SDGE_QF	Goal Line 1	CG	33	30	32	31	32	32	34	34	32	33	32	33
SDGE_QF	Kelco NutraSwe 1	GT_NG_Old	10	9	10	10	10	10	10	10	10	10	10	10
SDGE_QF	NavalStationCG 1	CC_NG_Old	30	27	29	28	29	29	30	31	29	29	28	30
SDGE_QF	North Island C 1	CC_NG_Old	24	22	24	23	24	23	25	25	24	24	23	24
SDGE_QF	NTC/MCRD Cogen 1	CC_NG_Old	15	14	15	14	15	15	16	16	15	15	15	15
SDGE_QF	SDGE Bio QF F 1	OT	3	3	3	3	3	3	3	3	3	3	3	3
SDGE_QF	SDGE Bio QF V 1	OT	5	4	5	5	5	5	5	5	5	5	5	5
SDGE_QF	SDGE Misc CG Q 1	CG	47	42	46	44	46	45	48	48	46	47	45	47

Capacity (MW)

UtilGroup	Station	Allocation	1/1/04	2/1/04	3/1/04	4/1/04	5/1/04	6/1/04	7/1/04	8/1/04	9/1/04	10/1/04	11/1/04	12/1/04
SDGE_Bilateral	SDGE_DWRN_1B		133	133	133	133	133	133	133	133	133	133	133	133
SDGE_QF	SDGE Bio QF F 1		5	5	5	5	5	5	5	5	5	5	5	5
SDGE_QF	SDGE Bio QF V 1		7	7	7	7	7	7	7	7	7	7	7	7
SDGE_QF	SDGE Misc CG Q 1		68	68	68	68	68	68	68	68	68	68	68	68

## Question 2

On page 18 of the Proposed Determination of Revenue Requirements for 2004, footnote 10 states that "all values in [Table D-7] have been adjusted for transmission and distribution losses." The SDG&E energy requirements shown in Table D-7 of 20,390 GWh is essentially the number provided to DWR in response to data requests, and is a number before transmission and distribution losses. The number is not net of losses. Please confirm whether the SDG&E numbers in Table D-7 are intended to be before losses or net of losses.

## Response

Table D-7 does not include the footnote referenced. The table containing the footnote and GWh's questioned is Table D-5.

Table D-5 reflects energy before it has been reduced for transmission or distribution losses.

## Question 3

On p. 24 of the Proposed Determination of Revenue Requirements for 2004, in the discussion of Extraordinary Costs, please clarify whether the 2003 collateral requirement of \$54 million is: 1. a forecast from a model run; 2. the collateral requirement incurred by DWR for 2003; or 3. a combination of 1 and 2. If not specified in the response to the prior question, how much collateral has DWR incurred for 2003? Finally, please provide the

amount of collateral for each of 2003 and 2004 specifically for the DWR contracts allocated to SDG&E.

### **Response**

The \$54 million 2003 collateral requirement is an actual requirement paid from the Operating Account to the brokerage handling DWR's gas transactions. The amount of collateral estimated for 2004 is based on the total gas supply required for the DWR portfolio of contracts.

### **Question 4**

On p. 27 of the Proposed Determination of Revenue Requirements for 2004, the Morgan Stanley capacity is listed as 50MW. This does not appear to reflect the recent renegotiation of the contract. Does DWR intend to include this in its Final Determination as it would affect the amount of energy delivered to SDG&E?

### **Response**

The renegotiation of the Morgan Stanley contract was not included in the Proposed Determination as originally provided. The Supplemental Additional Material, provided on August 6, 2003, does include updated information and in making this Determination, the Department has included the renegotiated Morgan Stanley contract in PROSYM.

### **Question 5**

In the Excel file provided by DWR called Contract Generation PS 42 7-16-03 the total DWR contract generation for SDG&E in 2004 is 5,114 GWh. The Proposed Determination shows on page 20 that SDG&E's supply from DWR contracts is 7,617 GWh. Please explain the difference.

### **Response**

The 7,617 GWh amount is correct. In the Excel spreadsheet that SDG&E received, three of the contracts were inadvertently allocated to SCE and they should have been allocated to SDG&E. These contracts are allocated correctly in PROSYM.

SDG&E should make the following changes to the spreadsheet.

Change from this:

SCE	6x16	SDGE APX
SCE	6x16	Williams B
SCE	6x16	Williams C

To this:

SDGE	6x16	SDGE APX
SDGE	6x16	Williams B
SDGE	6x16	Williams C

### Question 6

In addition to the monthly surplus sales volumes and revenues you have already provided, please provide a breakdown of the volumes and prices of SDG&E surplus sales by peak and off peak periods for each month.

### Question 7

Please provide the detailed electric and gas price forecasts used to forecast deliveries of DWR energy to SDG&E. SDG&E realizes that DWR's Proposed Determination on p. 23 includes an annual forecast of gas prices.

### Response to Questions 6 and 7

Following are tables expressing PROSYM typical week conversion factors and typical week hourly data for SDG&E. The typical week used by PROSYM is 168 hours long and can be divided up into peak and off peak hours. The summation of typical week data multiplied by the conversion factors will provide a monthly total. The third file is a monthly gas price forecast used for PROSYM Run 42.

PROSYM typical week conversion factors

The sum of the 168 hour typical week multiplied by the conversion factor will provide the total for the month.

ProSym Week	Month	Month Name	Monthly Conversion Factor
3	1	Jan	4.428571429
8	2	Feb	4
11	3	Mar	4.428571429
16	4	Apr	4.285714286
20	5	May	4.428571429
25	6	Jun	4.285714286
29	7	Jul	4.428571429
33	8	Aug	4.428571429
37	9	Sep	4.285714286
42	10	Oct	4.428571429
46	11	Nov	4.285714286
51	12	Dec	4.428571429

### March 2003 Revised CDWR Gas Price Forecast

#### So California Border

	2003	2004	2005
Jan	4.60	4.80	4.41
Feb	4.92	4.17	3.86
Mar	6.89	3.96	3.67
April	6.45	4.13	3.82
May	5.70	4.29	3.97
June	5.31	4.75	4.37
July	5.23	4.67	4.30
Aug	4.46	3.92	3.63
Sept	4.51	3.96	3.67
Oct	4.26	4.21	3.89
Nov	4.85	4.80	4.41
Dec	4.90	4.84	4.45
<b>Avg</b>	<b>5.17</b>	<b>4.37</b>	<b>4.04</b>

#### Citygate

	2003	2004	2005
Jan	4.89	5.14	4.74
Feb	5.16	4.39	4.08
Mar	7.53	4.08	3.80
April	6.35	4.14	3.85
May	5.49	4.19	3.89
June	5.13	4.62	4.26
July	5.05	4.54	4.20
Aug	4.35	3.84	3.58
Sept	4.50	3.98	3.71
Oct	4.37	4.33	4.01
Nov	5.07	5.02	4.63
Dec	5.24	5.18	4.78
<b>Avg</b>	<b>5.26</b>	<b>4.45</b>	<b>4.13</b>

**March 2003 CDWR Gas Price Forecast Update  
Stress Case**

So California Border

	2003	2004	2005
Jan	9.20	9.59	8.82
Feb	9.84	8.34	7.71
Mar	13.78	7.92	7.34
April	12.90	8.26	7.64
May	11.40	8.59	7.93
June	10.62	9.51	8.74
July	10.45	9.34	8.60
Aug	8.93	7.84	7.27
Sept	9.01	7.92	7.34
Oct	8.52	8.42	7.78
Nov	9.71	9.59	8.82
Dec	9.79	9.68	8.89
<b>Avg</b>	<b>10.35</b>	<b>8.75</b>	<b>8.07</b>

Citygate

	2003	2004	2005
Jan	9.78	10.27	9.48
Feb	10.32	8.78	8.15
Mar	15.06	8.16	7.60
April	12.70	8.28	7.69
May	10.99	8.39	7.78
June	10.26	9.24	8.53
July	10.11	9.08	8.39
Aug	8.70	7.69	7.16
Sept	9.00	7.96	7.41
Oct	8.75	8.65	8.03
Nov	10.15	10.03	9.26
Dec	10.48	10.36	9.55
<b>Avg</b>	<b>10.52</b>	<b>8.91</b>	<b>8.25</b>

**Comment 2: Transmission loss impact on load requirements**

The inclusion of SDG&E service area transmission losses in SDG&E's load requirement could cause SDG&E's load to be overstated. The additional SDG&E load requirement can result in overstating the energy needed from DWR dispatchable contracts. Since the majority of SDG&E's Utility Retained Generation ("URG") is limited to fixed energy resources, any change in SDG&E load requirement tends to be served by DWR dispatchable contracts. As a result, DWR dispatchable contract output can be overstated by

the amount of service area transmission losses. In the DWR data provided to SDG&E, area transmission losses represent about 12% of the total energy delivered by DWR dispatchable contracts. SDG&E recommends that transmission losses be handled by following the current ISO market design where resources are dispatched to serve load requirements that exclude transmission losses. Transmission loss costs are then accounted for on a resource specific basis, either by the variable costs necessary to physically cover the losses or an ISO imbalance charge to financially cover the losses. If transmission losses were handled in this manner, the additional energy to account for transmission losses only would amount to 2-3% of the total energy delivered by DWR dispatchable contracts.

**Response:**

The Department agrees that the inclusion of transmission losses in SDG&E's load requirements calculation could cause SDG&E's load to be overstated. The Department is currently reviewing its load forecasting approach and in the future will make any changes necessary to better mimic actual market operations. The Department believes that the impact of any overstatement described by SDG&E on the 2004 Revenue Requirement is minimal, and represents less than a \$5 million in costs. The Department does not intend to modify its 2004 Revenue Requirement on the basis of the present comment.

**Comment 3: DWR's A&G costs are too high**

SDG&E is concerned that DWR's A&G costs do not appear to be decreasing to correspond to the reduced scope of DWR's duties. This lack of a decrease appears to confirm SDG&E's observation that DWR is duplicating some of the work SDG&E does to comply with CPUC orders. For example, the CPUC has ordered the utilities in their respective Operating Agreements and DWR has agreed that SDG&E should verify almost all payments that DWR makes to its electric and gas suppliers. DWR, however, apparently continues to maintain staff and consultants to perform this function. The unfortunate consequence of this duplication in efforts is that customers pay twice: once to DWR and again to the IOUs. SDG&E, therefore, requests that DWR explain in detail the reasons its costs have not decreased and coordinate with SDG&E and the CPUC to minimize future duplication of efforts.

**Response:**

DWR has significantly decreased its direct expenditures for A&G costs. However, as stated on pages 29 and 30 of the Proposed Revenue Requirement, \$28 million (48%) of the 2004 A&G costs are associated with pro rata charges for services provided to the Power Supply Program by other State agencies. Under the methodology used by the State's Department of Finance to develop the Statewide Pro Rata charge, this is the first year that any charge has been allocated to the Power Supply Program. The Statewide Pro Rata methodology includes a true up of costs in the second preceding budget year as well as estimated current budget year costs. Therefore, since the Power Supply Program was not in existence at the time the 2001-2002 allocation was initially determined, the true up charges for 2001-2002 (\$14 million) included in the 2003-2004 budget are substantially the

same as the estimate (\$14 million) for the 2003-2004 pro rata charge. Without the pro rata charge, the A&G costs would have been projected to decrease by 37% from 2003.

DWR agrees with SDG&E that every effort should be made to reduce duplication of efforts; however, since the payments being made to electric and gas suppliers represent payments of DWR funds, and DWR has the financial and legal responsibility for the contracts, it is appropriate that DWR perform an invoice validation process before releasing Electric Power Fund monies. Also, to date the utilities have not provided complete settlement efforts in the verification of payments. DWR's efforts to finalize settlements has led to a reduction in payments to electricity and gas suppliers over what had been approved by various utilities, thereby creating cost savings to California ratepayers.

#### **PRELIMINARY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON JULY 17, 2003 DWR PROPOSED DETERMINATION OF REVENUE REQUIREMENTS FOR 2004**

The PG&E comments were provided in sections including a brief introduction and an executive summary of comments and recommendations and a conclusion. The comments were grouped in broad areas of concern, which are summarized and addressed below.

#### **Legal and procedural requirements applicable to DWR's revenue requirements**

##### **Comment 1. Compliance with Section 451 of the Public Utilities Code**

DWR's Proposed Determination of its revenue requirements does not meet its burden of proof to show "clear and convincing" evidence, and therefore is not in compliance with Public Utilities Code Section 451.

#### **Response:**

PG&E argues that the Department has failed to meet its legal burden required by California Public Utilities Code § 451. PG&E argues that the Department must demonstrate by *clear and convincing evidence* that its costs are just and reasonable and that the Department bears the burden of proof to produce evidence of having the greatest probative force to support a just and reasonable determination. PG&E's comments misapplies evidentiary standards applicable to regulated utilities in Commission proceedings to DWR. California Public Utilities Code § 451 provides as follows:

All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

All rules made by a public utility affecting or pertaining to its charges or service to the public shall be just and reasonable.

California Public Utilities Code § 451 does not establish a burden of proof. Instead, PG&E relies on Commission Decision 00-02-046 which describes the Commission's procedures applicable to examining a utility's revenue requirement pursuant to § 451. PG&E identifies the correct burden of proof applicable to utilities in Commission proceedings addressing the just and reasonableness of utility revenue requirements. In this case, however, the Department has established procedures to examine its own revenue requirements in order to determine whether they are just and reasonable consistent with AB1X and § 451 of the Public Utilities Code. This is not a proceeding before the Commission.<sup>20</sup> The Department's procedures require that the record must demonstrate by substantial evidence that the Determination of Revenue Requirements is just and reasonable.<sup>21</sup> The Department notes that this evidentiary standard is consistent with the standard of judicial review applicable to Commission Decisions, which requires that findings be supported by substantial evidence in light of the whole record.<sup>22</sup>

#### Comment 2: Compliance with the Water Code

DWR substantially failed to meet the criteria established by Section 80100, and as a result entered into contracts that committed DWR to buy too much power over the long term during non-peak periods, while not procuring enough power under contract during peak periods.

#### **Response:**

PG&E asserts that Water Code § 80100 establishes additional criteria the Department must meet under its power purchase program. The Department agrees that Water Code § 80100 provides additional criteria for the Department to assess its power purchase program. The Department has expressly incorporated these criteria in its Regulations to determine if its costs are just and reasonable.

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<sup>20</sup> Water Code § 80110.

<sup>21</sup> Title 23 California Code of Regulations § 517.

<sup>22</sup> California Public Utilities Code § 1757 (a)(4).

Water Code § 80100 provides:

Upon those terms, limitations, and conditions as it prescribes, the department may contract with any person, local publicly owned electric utility, or other entity for the purchase of power *on such terms and for such periods as the department determines and at such prices the department deems appropriate* taking into account all of the following....

- (1) The intent of the program is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt hour.
- (2) The need to have contract supplies to fit each aspect of the overall energy load profile.
- (3) The desire to secure as much low-cost power as possible under contract.
- (4) The duration and timing of contracts made available from sellers.
- (5) The length of time sellers of electricity offer to sell such electricity.
- (6) The desire to secure as much firm and nonfirm renewable energy as possible.<sup>23</sup>

(Emphasis Added)

Section 80010 thereby specifically provides a standard for the terms, periods and prices for the Department to utilize in entering into power purchase agreements. Other sections of AB1X also provide general guidance and direction for the power supply program. The statute's statement of purpose<sup>24</sup>, the list of factors for the power purchase contracts, and the full-cost-recovery financing system provide the framework for determining if the revenue requirement is "just and reasonable." PG&E asserts that the Department failed to consider these factors in entering into long term contracts. PG&E is incorrect. The Department considered the provisions of Water Code § 80110 in implementing its power purchase program<sup>25</sup> and has also considered these factors in finding its 2004 Revenue Requirement just and reasonable.

### Comment 3: Compliance with California Administrative Procedure Act

DWR's regulations are void because they directly conflict with, and purport to diminish, the APA's requirements and, as such, these regulations cannot govern the promulgation of DWR's just-and-reasonable determination.

In promulgating its revised permanent procedural rules, DWR unlawfully extended its prior emergency procedural rules in December 2002, without prior notice and opportunity for public comment.

DWR's just-and reasonable determination cannot stand because DWR has failed to even comply with its own minimal standards.

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<sup>23</sup> California Water Code Section 80100.

<sup>24</sup> California Water Code Section 80000.

<sup>25</sup> See e.g. Declaration of Ronald O. Nichols dated August 8, 2002.

The just-and reasonable determination violates Section 513 because it relies on “significant additional material” that was not made part of the record, and has not been made available for review by interested parties and the public.

DWR has unlawfully refused to fully disclose to the public the documents and information it is relying on.

DWR must re-notice and re-promulgate its proposed revenue requirement determination in full compliance with the procedural safeguards of the Ca. APA.

**Response:**

PG&E argues that the proposed regulations are unlawful because they provide for procedures that are different than the procedures set forth in the APA for the promulgation regulations. PG&E asserts that the Department’s regulations cannot govern the promulgation of DWR’s just and reasonable determination because they conflict with and diminish the requirements set forth in the APA. PG&E also asserts that DWR unlawfully extended its emergency regulations in December 2002. Contrary to PG&E’s arguments, the Department’s regulations have been promulgated pursuant to the APA and the Department’s emergency regulations were extended with the approval of the Office of Administrative Law (“OAL”).<sup>26</sup> DWR’s regulations governing its determination of a revenue requirement are now permanent. PG&E’s argument appears to assume that a determination of revenue requirements itself constitutes a regulation and that the Department must re-notice and promulgate the 2004 Proposed Revenue Requirement as a regulation under the procedures set forth in the APA. For the reasons set forth in its Final Statement of Reasons submitted to OAL, DWR disagrees with PG&E’s interpretation.<sup>27</sup>

PG&E also asserts that DWR has relied on additional significant material that was not made part of the record of this administrative proceeding and has not disclosed to the public all information upon which it is relying to determine its revenue requirements. PG&E’s contention that DWR has relied undisclosed information to support its Proposed 2004 Determination is incorrect. The Department is relying only on those materials contained within the administrative record to support this Determination of Revenue Requirements and just and reasonable determination.

**DWR has not demonstrated that its power charge revenue requirements and costs for its long-term power contracts are just and reasonable**

Comment 4: The State of California Has Determined That Certain of DWR’s Long Term Contracts Were Unjust and Unreasonable When Entered Into and Therefore Up to \$2 Billion of DWR’s Long Term Contract Costs Are Not “Just and Reasonable”

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<sup>26</sup> June 5, 2003 Final Statement of Reasons submitted to OAL at p. 5. As part of the administrative record underlying this Determination of Revenue Requirements, the Department has included its Final Statement of Reasons submitted to the OAL on June 5, 2003 in connection with the promulgation of regulations governing procedures to determine a revenue requirement.

<sup>27</sup> Final Statement of Reasons at pp. 2-5.

Response:

PG&E argues that proceedings initiated by California state agencies before the Federal Energy Regulatory Commission ("FERC"), effectively preclude DWR from finding that power costs associated with its long term contracts are just and reasonable. The Department has expressly recognized the State of California's efforts to pursue refunds, lower prices or changes to the terms and conditions of long term power purchase contracts through litigation before FERC.<sup>28</sup> To the extent the Department's long-term contracts are modified by order or through renegotiation, these modifications will be incorporated into future Determinations. However, under its regulations, the Department must consider whether its Revenue Requirements are just and reasonable within the legal framework established by AB1X. The litigation before FERC, which was initiated by the Commission and the California Electricity Oversight Board, alleges that under Section 206 of the Federal Power Act, the Department's long-term contracts are not just and reasonable due to the market power that suppliers exercised at the time the Department was placed in the position of obtaining contracts to assure reliable service and reduce the cost of energy. This contention is not inconsistent with a Determination that power costs incurred by the Department and included within a determination of revenue requirements are just and reasonable.

Comment 5: The California State Auditor's December, 2001 and April, 2003 Reports Have Identified Numerous DWR Contracting Decisions That Have Imposed Significant Cost Risks on Consumers and Therefore Have Not Been Demonstrated by DWR to be Prudent or Reasonable

**Response:**

PG&E complains that DWR's Determination does not respond to the conclusions of the California State Auditor's Reports. PG&E argues that the 2004 Proposed Determination is not supportable without an assessment and evaluation of the findings and conclusions of the Audit Reports. DWR disagrees. The Department has reviewed and responded to the State Auditor's Reports. Although the Department fully intends to continue to consider and evaluate the Reports of the California State Auditor in connection with administering the power supply program, it is not necessary to rebut or respond to each and every statement of the California State Auditor in determining a revenue requirement. A determination of revenue requirements establishes the Department's costs associated with its power supply program. To accomplish this, the Department identifies all the costs and projected costs attributable to the program for a particular period and aggregates such costs to derive the Department's revenue requirement. The revenue requirement is essentially a calculation of costs associated with the Department's power purchase program and not an assessment of the conclusions of the California State Auditor.

To the extent PG&E's argument seeks to challenge any just and reasonable determination that does not contain an assessment and evaluation of the California State Auditor's Reports, such a requirement is not contained within the Department's regulations

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<sup>28</sup> August 16, 2002 Determination of Revenue Requirements at p. 66.

governing that establish standards to determine whether a revenue requirement is just and reasonable. The Department's Regulations require that a just and reasonable determination be supported by substantial evidence in the record.<sup>29</sup> There is substantial evidence contained in the Department's administrative record which rebuts or responds to criticism contained in the State Audit report.<sup>30</sup>

**Comment 6: PG&E's Expert Evaluation of DWR's Quasi-Legislative Record in its 2003 Determination Applies to DWR's 2004 Proposed Determination As Well**

**The Record Lacks Sufficient Evidence To Support DWR's Just-and-Reasonable Determination**

**DWR Acted Imprudently By Executing Billions of Dollars of Contracts at a Time When DWR Believed the Market for Long-Term Power Was Dysfunctional**

**The Record Lacks a Net Present Value Analysis Needed to Analyze DWR's Decision to Purchase Long-Term Power**

**The Record Lacks Evidence Regarding DWR's Decision To Accept Power at Particular Locations**

**The Record Lacks Evidence Regarding Whether the Costs Incurred Under Particular Contracts Are "Just and Reasonable"**

**The Proposed Determination Lacks the Necessary Information to Evaluate the Reasonableness or Ratepayer Benefits of DWR's Renegotiated Contracts to Support the 2004 Revenue Requirements, and DWR Is Unlawfully Refusing to Make Such Information Public**

**Response:**

PG&E has submitted a declaration of Eugene T. Meehan, a purported expert, and relies on Mr. Meehan's statements in this section of its comments.<sup>31</sup> The statements of Mr. Meehan and comments of PG&E with respect to the prudent person standard relied on in this section are incorrect or incomplete in certain respects. First, DWR has not "admitted" that the standards for just and reasonable include a prudent person standard; instead DWR has stated that it used a prudent person standard in addition to the legally required standard, "although by law only the standard stated in the [DWR] regulations governs such review." (DWR 06344.)

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<sup>29</sup> Title 23 California Code of Regulations, Section 517.

<sup>30</sup> See e.g., Memorandum dated October 4, 2001 from the Department of Water Resources to Thomas M. Hannigan regarding Status Report on Conclusion of DWR Power Purchase Contract Efforts. Memorandum dated December 10, 2001 from the Department of Water Resources to Mary D. Nichols regarding Department of Water Resources' Response to the State Auditor's Draft Report

<sup>31</sup> The Declaration of Mr. Meehan was originally filed by PG&E in its legal action challenging the 2002 revenue requirement. The Court in that proceeding granted DWR's motion to strike the Declaration.

Second, although Mr. Meehan states he relies on the standards for a “traditional prudency review,” as the CPUC has noted, “there are many versions of the term ‘reasonable and prudent’.” (D87-06-021, 24 CPUC2d 476, 486.) In that decision, the CPUC stated as follows:

The term "reasonable and prudent" means that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost effectiveness, reliability, safety, and expedition.

A "reasonable and prudent" act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction. (*Id.*)

Although PG&E relies on Mr. Meehan as an expert, it does not appear that Mr. Meehan has personal knowledge or expert credentials with respect to the revenue requirement determination under California law, and specifically AB 1X. Mr. Meehan’s resume indicates he has a B.A. degree in economics and has been a utility consultant for 25 years in states *other than California*. Although the resume asserts he has testified as an expert before various commissions, it does not indicate the subject matter of his testimony. The declaration is based on Mr. Meehan’s purported knowledge of generic or traditional regulatory practices, which are not defined. (For example, ¶6 (“the regulatory precedent”); ¶7 (“regulatory economics and regulatory practice... both in California and nationally”), ¶12 (“a regulatory body”), ¶25 (“traditional prudency review”).) The declaration does not establish that the regulatory practice upon which the declaration is based confers expert knowledge of California regulatory practice, the circumstances present in California at the time of the energy crisis in 2000-2001, or the issue of whether the DWR has acted appropriately pursuant to AB1X.

Response to PG&E comment that the record lacks sufficient evidence to support DWR’s just-and-reasonable determination

PG&E contends in this section that the record of the 2003 revenue requirement contains insufficient evidence to support a just and reasonable determination. PG&E asserts that the record contains insufficient comparisons to forward-market prices, citing the testimony of Susan Lee of DWR that such comparisons were made. As reflected in Ms. Lee’s testimony, some of this data was from voice broker services, i.e., communicated orally, not in writing. Also, the record contains evidence of DWR’s use of an estimated market price proxy forecast. (DWR I, 02535-02547).

PG&E specifically criticizes the Calpine June 11 contract as exceeding a contemporaneous forward-market price quote obtained by Mr. Meehan. Meehan claims the Calpine transaction was overpriced based on his comparison of the average price of the contract power to the price for “similar products” available in the “over-the-counter” forward market, citing a broker quote sheet for June 11 that he says shows (or yields) a forward price for NP15 6x16 power over the term of the Calpine contract of \$51/MWh “levelized”. He compares this price to his calculated “levelized” price for Calpine of \$108/MWh. Meehan characterizes the 6x16 product as a “similar product,” though “slightly different.” He concludes that the differences “are not so large as to justify a price for the Calpine transaction of more than twice the block forward price.” However, this price comparison is inappropriate. The Calpine contract provides for dispatchable power from new generation resources. The power product was dispatchable capacity, callable for up to 4000 hours/year. DWR’s scheduling rights provided for day-ahead scheduling, with 1000 of the hours callable on an intra-day basis. The cost of obtaining such option rights is reflected in the capacity payment for the product.

Dispatchable capacity is a totally different product from a block of must-take energy. As acknowledged in the first State Audit:

“If the department is to meet its statutory mandate to secure ‘contract supplies to fit each aspect of the overall energy load profile,’ it must plan for and obtain sufficient energy supplies to meet consumer demands over time. In particular, the department must have enough additional capacity to meet peak-demand conditions. More specifically, the department must plan for sufficient capacity to respond to normal hourly, daily, monthly, and yearly variation in loads and to generating facility outages. It must also plan for the occasional peak-load conditions during which peakers will be dispatched to preserve system reliability and spot prices will be particularly high. In short, those pursuing contracts to meet the net short must be cognizant of both energy and capacity needs.” (DWR II, 04862).

The audit also recognizes that the price of capacity is different from the price of energy:

“Different power products have different lowest possible prices. . . Other factors affecting the price include the hours of the day and the months of the year the power is delivered and whether the buyer has the option to refuse the power if it is not needed.” (DWR II, 04890). “In the 24-hour base-load product, the generator has no down time and thus recovers its investment as quickly as possible. With peaking power, however, the generator’s plant stands idle until the buyer demands the power, and thus the price must be increased to reflect the time that the investment in the generator is simply on hold, waiting for the buyer to dispatch the power.” (04890).

“It is possible that acquiring a greater proportion of peak contracts [i.e. “peaking capacity purchases”]—which provide power for fewer hours per year—might ultimately represent the best means for minimizing overall electricity costs to

consumers to the extent that these contracts would shield consumers from price spikes in spot markets during periods of peak demand.” (DWR II, 04857).

PG&E also challenges DWR’s use of a benchmark price of 7 cents. First, DWR did not solely rely on this benchmark, as the record demonstrates. Second, this benchmark was not the creation of DWR, and its appropriateness is evidenced in part by the fact that it was reflected in CPUC-approved rates, and supported by FERC determinations. FERC’s December 15, 2000 order (93 FERC P. 61,294 at 27) “found that an average of historical utility embedded cost of generation would represent an appropriate benchmark for determining the prudence of forward contracts” (cited in CPUC D01-03-067, DWR I at 05510). CPUC D01-03-067 cites FERC’s figure of \$67.45/MWh as “an average” of historical utility embedded generation costs (DWR I, 05510). The figure was cited by FERC based on information, provided to FERC in comments, which was based on CPUC D97-08-056 (DWR I, 05501). The IOU-weighted average generation cost reflected in CPUC D01-04-005 on calculating the California Procurement Adjustment (CPA) is \$70.00/MWh. (DWR II, 06016).

Mr. Meehan criticizes the 7-cent benchmark based among other things on citation to CPUC D01-03-067 (DWR I, 05510) to show a rate of \$67/MWh, although CPUC D01-04-005 (DWR II, 05989) shows a rate of \$70. (Attachment E to the latter decision cited contains IOU generation rates and associated AB1X GWh that yield a weighted average rate of \$70.00/MWh. See DWR II, 06016). The decision to which Mr. Meehan cites, however, is a decision on QF pricing, and the decision actually uses DWR costs during 2001-2006 (\$79/MWh) as a reasonableness benchmark for QF pricing. (DWR I, 05481).

Response to PG&E comment that DWR acted imprudently by executing billions of dollars of contracts at a time when DWR believed the market for long-term power was dysfunctional

This issue has been addressed above and in DWR’s filings in litigation brought by PG&E. To the extent relevant to the assertion of Mr. Meehan that a “prudence” standard is appropriate, it is significant that under the CPUC definition, as under any reasonable analysis, cost savings cannot come at the expense of reliability, and the record contains ample evidence that DWR’s actions helped restore reliability and lower spot market energy prices.

Response to PG&E comment that the record lacks a net present value analysis needed to analyze DWR’s decision to purchase long-term power

PG&E relies on Mr. Meehan’s statements concerning the need for a net present value analysis, although as indicated above the basis for his expertise with respect to the DWR’s actions pursuant to AB 1X is unclear. While DWR did conduct net present value analyses, they remain confidential due to DWR’s continuing effort to renegotiate certain contracts. These analyses comported with DWR’s decisions, but were just one of the factors considered.

Response to PG&E comment that the record lacks evidence regarding DWR's decision to accept power at particular locations

PG&E and Mr. Meehan question DWR's decision to accept power at certain locations in Southern California, and assert the record lacks information about this decision. However, the net short analyses and contract modeling were done on a zonal basis, considering the delivery location. (See Initial Evaluation of CDWR RFB#2, Table 4 (DWR I, 03673), which lists zonal estimated net short in 2001 and 2002 remaining after the PX block forwards and RFB1 award; initial net short calculations, by zone, provided by CAISO (DWR I, 05653-05659); load profile contracting charts, by zone (DWR I, 02654-02656, 02666-02668) as well as the February 2001 net short energy quantity and cost model (CD 3 listed in DWR II Index of Record, page 13 (Purch\_Sale 23—2-26-01-Submitted-fmt.xls; see Monthly Bidding tab)). In addition there was evidence that grid expansions were planned in the near future which would allow SP power to serve NP. (See letter from Transmission Agency of Northern California to Governor Davis on April 9, 2001, stating that "TANC . . . was planning to complete Path 15 upgrades by late 2002 and we were on track to do so" before Governor elected not to sign an Executive Order providing funding. (DWR I, 04322-04323) As is noted elsewhere in the record, in April 2001, the Commission requested PG&E to file an application for Certificate of Convenience and Necessity to perform upgrades to Path 15)).

Response to PG&E comment that the record lacks evidence regarding whether the costs incurred under particular contracts are "just and reasonable" and that the proposed determination lacks the necessary information to evaluate the reasonableness or ratepayer benefits of DWR's renegotiated contracts to support the 2004 revenue requirements, and DWR is unlawfully refusing to make such information public

PG&E, citing the Meehan declaration, criticizes the renegotiation of certain long term contracts. PG&E appears to suggest that DWR should have addressed the problem of unfavorable terms in some of its long term contracts by renegotiating them to remove those terms. Any such renegotiation can only succeed, however, if the energy seller agrees to such terms. PG&E also asserts, without citation, that DWR is unlawfully refusing to make certain information provided to the State Auditor public. As noted above, some of the information is confidential, and its disclosure has the potential to impair DWR's position with respect to power sellers.

The Meehan declaration specifically critiques two renegotiated contracts, Calpine and GWF. He does not conclude that the contracts are not just and reasonable, but simply that there are questions and that he would like to investigate further. As to the Calpine contract, as stated above, Mr. Meehan's critique is based on an inappropriate comparison between 6x16 power and dispatchable capacity.

As to the GWF contract, Mr. Meehan asserts that it resulted in higher power prices. In fact, the renegotiated contract is a net benefit to DWR. It contains a reduction in fixed costs (capacity price reduction), and a decrease in the number of possible dispatchable hours. Mr. Meehan appears to have used erroneous methodology. It appears he has averaged the

total cost of power under each of the contracts (original and renegotiated) over the maximum energy available under the respective contract. As the number of dispatchable hours was reduced, the fixed costs under the new contract were averaged over a smaller number of hours than were the fixed costs under the original contract, leading to a higher “average price”, despite the lower amount of actual fixed costs.

Mr. Meehan’s analysis is based on the erroneous assumption that the original contract would have resulted in 4000 hours/year of actual dispatch (over a 45% capacity factor). Peaking resources with heat rates of 10,000-12,000 Btu/kWh can generally be expected to run about 500 to 2000 hours/year (a capacity factor of less than 25%). GWF units with a heat rate of 10,340 Btu/kWh were forecast to operate for less than 2000 hours/year during 2003-2008, and the GWF units with a heat rate of 11,890 Btu/kWh were forecast to operate for less than 1200 hours/year through 2011. (PSYM 36 data contained in CD5, DWR II Index of Record.) Thus, Meehan’s computation of “average price” under the original contract is based on an unrealistic assumption. Even using his methodology of averaging contract costs over assumed contract energy, a more realistic assumption on capacity factor would drive his computed average cost for the original contract upward toward, and above, the average cost for the new contract.

A second problem concerns Meehan’s methodology, even accepting a 4000 hour/year assumption for original contract dispatch. The appropriate basis of comparison between the two contracts should not be the average cost to supply different amounts of power, but the effect on total cost to meet the same amount of net short load. Using Meehan’s assumption that there would have been 4000 hours/year used under the original contract, he should have compared the cost to supply those 4000 hours under the original contract with the cost to supply equivalent power for 4000 hours using the new contract. Since the new contract is limited to 2000 hours, an additional 2000 hours of replacement energy should have been incorporated in order to match the energy assumed under the original contract (and then costs could be divided by 4000 hours of energy in both cases). Because of the reductions in fixed costs, the replacement energy could even be bought for a premium over the contract energy price and the total cost to meet the 4000 hours of energy would still be lower with the new contract (and the “average price” would be lower as well since both averages would be for 4000 hours of power).

### **Comments on DWR’s significant additional materials released August 6, 2003**

**Comment 7:** DWR released significant additional materials related to the Proposed Determination; but did not re-notice its Proposed Determination and allow the full 45-day period for comments on the additional material required by the Cal. APA.

#### **Response:**

PG&E argues that the Department must provide a 45 day period to allow interested persons to comment on significant additional material for which the Department has provided notice to interested persons that it intends to rely in reaching a determination

of revenue requirements. PG&E's argument is based on the assumption that the revenue requirement itself constitutes a regulation under the APA and that the APA procedures for adopting regulations should be the same as the Department's procedures for reaching a revenue requirement determination. As explained the Final Statement of Reasons submitted to OAL in connection with the Department's Rulemaking Action to adopt permanent regulations for reaching a revenue requirements determination, PG&E has conflated the applicability of the APA to the promulgation of the Department's proposed regulations governing the process for making a determination of revenue requirements with the Department's determination of revenue requirements itself (itself is not a regulation).<sup>32</sup> Under PG&E's approach, each and every revenue requirement determination would be considered a regulation subject to the processes and requirements set forth in the APA. However, the revenue requirement is not a "regulation", as that term is defined in the APA. A regulation subject to the APA has two principal identifying characteristics: (1) the agency must intend its rule to apply generally, rather than in a specific case;<sup>33</sup> and (2) the rule must "implement, interpret, or make specific the law enforced or administered by [the agency], or ... govern [the agency's] procedure."<sup>34</sup>

A revenue requirement determination made by the Department pursuant to the proposed regulations will not establish a rule of general application, nor does the Department intend for any particular determination of revenue requirements to apply generally. To the contrary, for each revenue requirement determination, the Department will consider specific facts for a specific period of time. Successive determinations will be made for specified time periods, on an annual or more frequent basis. The Department intends to make revenue requirement determinations in accordance with the statutory requirements of AB 1X, on a case by case basis, separately for each year. Thus, each periodic establishment of a revenue requirement is a one-time activity which does not meet the statutory definition of a "regulation."<sup>35</sup>

Section 513 of the Department's regulations provides:

If following a notice pursuant to section 512 (notice of opportunity to submit comments) the department identifies significant material that it intends to rely upon in making its determination, but which was not identified in the proposed determination, the department shall provide notice of such additional material to those persons who received the original notice by the same means as the original notice. The notice

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<sup>32</sup> Final Statement of Reasons dated June 5, 2003 at pp. 3-5.

<sup>33</sup> Government Code § 11342.600 provides that a regulation "means every rule, regulation, order, or standard of general application or the amendment, supplement, or revision of any rule, regulation, order, or standard adopted by any state agency to implement, interpret, or make specific the law enforced or administered by it, or to govern its procedure." *Id.*

<sup>34</sup> Government Code § 11342.600. An agency's action is a regulation only if it is intended as a rule of general application.

<sup>35</sup> Final Statement of Reasons dated June 5, 2003 at pp. 3-5.

will also explain how the material will be made available for review.”<sup>36</sup>

The purpose of Section 513 is to provide an opportunity to comment on significant additional material relied upon by DWR in making its determination in order to ensure that the public has a meaningful opportunity to provide input on all the material DWR relies upon. Providing this opportunity ensures that the revenue requirement is subject to public scrutiny. The regulation provides for a reasonable period of time for comments instead of setting specific time periods because DWR does not know how much time will be available between the making of a determination and the time when a revenue requirement must be submitted to the CPUC under the directives of AB 1X.<sup>37</sup> The Regulations do not require that DWR “re-notice” its Proposed 2004 Revenue Requirements determination in the event that the Department intends to rely on additional significant material.

**Comment 8:** Some of the additional material relates to DWR’s contract renegotiations, and reinforces the fact that DWR is relying on non-public information, which it has not disclosed as part of its Proposed Determination.

**Response:**

PG&E argues that significant additional material noticed by DWR relates to renegotiated long-term power contracts. PG&E is correct. However, PG&E reaches an improper conclusion that this information reinforces PG&E’s argument that DWR is relying on or intends to rely on information which is outside of the administrative record supporting this Determination. The additional materials noticed by the Department include settlement agreements executed in connection with the renegotiated contracts. The settlement agreements were executed by the California Public Utilities Commission, the Energy Oversight Board, the Governor’s Office and the Department of Justice. The Department relied, in part, on the expertise of these various organizations in entering the settlement agreements and renegotiated contracts. The inclusion of these agreements in the administrative record of this proceeding supports this fact. In addition, the Department has also noticed its intention to rely on press releases issued by the Governor of the State of California, which describe the benefits of these renegotiated contracts. The materials within the administrative record demonstrate that the costs associated with the Department’s renegotiated contracts are appropriately included within the 2003 Revenue Requirement Determination.

**Comment 9:** DWR refused to respond to PG&E’s data requests.

**Response:**

During the course of DWR’s administrative proceeding PG&E submitted written “data requests” to representatives of DWR. The Department’s regulations do not provide for data requests such as the requests submitted by PG&E. However, at the request of interested

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<sup>36</sup> Title 23 California Code of Regulations § 513.

<sup>37</sup> Initial Statement of Reasons dated March 7, 2003 at p. 5

persons, including PG&E, the Department held several conference calls to answer questions concerning its Proposed Determination of Revenue Requirements for 2004. In addition, as described in applicable notices provided to the public, including PG&E, the Department has made its administrative record supporting its Proposed Determination of Revenue Requirements for 2004 available for inspection and copying. To date, PG&E has not requested to inspect or copy the Department's administrative record.

**DWR has not demonstrated that other cost components and forecast assumptions in its 2004 proposed revenue requirements are reasonable**

Comment 10: DWR's 2004 Power Charge Revenue Requirement Must Be Reduced To Reflect The El Paso Settlement

**Response:**

The Settlement agreement with El Paso provides for regulatory review, which is not complete. Until this review is complete and the final outcome assured no price changes will be reflected in the PROSYM data.

Comment 11: DWR's 2004 Power Charge Revenue Requirements Must Be Reduced to Reflect Renegotiation of the Allegheny and Morgan Stanley Contracts

**Response:**

Changes related to the Allegheny and Morgan Stanley contract renegotiations have been included in the PROSYM data underlying this Revenue Requirement Determination

Comment 12: DWR Includes Generation From Renewable Contracts In Its Revised Revenue Requirement That Should Be Addressed Separately

**Response:**

The Department only includes its costs in the Revenue Requirement. Allocation and Rate considerations regarding Department power are the responsibility of the CPUC. The PG&E renewable contracts are considered Long Term Power Contracts for purposes of this revenue requirement.

Comment 13: DWR Presents No Reasoned Justification For Its Administrative and General Cost Reimbursements To Other State Agencies

**Response:**

As a base for developing its A&G costs for the 2004 Revenue Requirement, DWR used its 2003-2004 fiscal year budget appropriation as passed by the Legislature, and signed by the Governor. DWR used the same amount for the 2004 calendar year as was used for the

State budget's fiscal year ending June 30, 2004. This is appropriate as it is anticipated that A&G costs are incurred evenly throughout the year, and there are no expected significant increases or decreases to be incurred in calendar 2004 as compared to the 2003-2004 fiscal year.

PG&E is correct in stating that \$14 million of the costs to be paid in calendar 2004 are attributable to prior years pro rata costs that had not been previously allocated to DWR. However, it is appropriate to include them in the 2004 Revenue Requirement as the cash payment for the services will be made in 2004.

Pro rata charges to DWR for costs incurred by other State agencies represents 48% of DWR's A&G costs for 2004. The \$28 million pro rata charge (\$14 million for fiscal year 2001-2002 and \$14 million for the current year) for other state agencies costs to be reimbursed by various state programs is determined by the State Department of Finance, a separate department within the State. A general overview of the Department of Finance's development of pro rata charges, as well as the details of the calculation and allocation applicable to the DWR and its Electric Power Fund, can be found on the Department of Finance's web site starting at [www.dof.ca.gov/FISA/PROSWCAP/general\\_overview.htm](http://www.dof.ca.gov/FISA/PROSWCAP/general_overview.htm). These pro rata costs are allocated directly to the Power Supply Program through the State's budgetary process and are to be paid by the Power Supply Program.

The pro-rata costs for services provided by other agencies of the State are in addition to the direct A&G costs which the Department has paid in prior years and will continue to pay in 2004.

**Comment 14: DWR's Bond Charge Revenue Requirement Assumes Too High An Interest Rate For Unhedged Variable Rate Bonds**

**Response:**

Pursuant to the Bond Indenture, the Department is obligated to budget for unhedged variable rate interest at the greater of (a) 130% of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation or (b) 4.0%. The 2004 Revenue Requirement budgets interest costs for unhedged Variable Rate Bonds at 4.0% which is greater than 130% of the highest average rate on the Variable Rate Bonds under the Bond Indenture formula.

To the extent that actual interest costs on unhedged Variable Rate Bonds are lower than the budgeted level in any year, the surplus collected during the year will serve to reduce the amount required to be collected from ratepayers in the following year. There will be, therefore, a "true-up" of interest costs with each revenue requirement filing.

**Comment 15: DWR Has Not Supported Its Costs Of Maintaining The Bond Debt Service Reserve Account**

**Response:**

The sizing of the Debt Service Reserve Account is prescribed in the Bond Indenture as the projected maximum annual debt service on the Bonds. Assuming that unhedged Variable Rate Bonds accrue interest at 4.0%, the lowest rate permitted in the Bond Indenture, the Debt Service Reserve Requirement must be maintained at \$927 million. The monies held in the Debt Service Reserve Account are currently invested in the State's Pooled Money Investment Account awaiting the opportunity to invest the monies in longer-term securities that will allow the Department to earn the maximum allowable yield under federal regulations. The Department anticipates that it may be able to secure these investments in the near term, but its ability to do so is not guaranteed. Until these higher-yielding investments are secured, the Department will continue to project interest earnings on the Debt Service Reserve Account based on the yield of the Pooled Money Investment Account.

Comment 16: DWR Has Provided No Justification For Its Inclusion Of \$71 Million of "Extraordinary Costs," And So These Costs May Not Be Included In DWR's Revenue Requirement

**Response:**

The table below illustrates expected fuel usage for calendar year 2004. The source of the data is PROSYM Run 42 underlying the Department's 2004 Revenue Requirement. The estimate of \$71 million is based on using gas futures contracts to hedge June through December 2004 gas requirements. The final amount will be based on using gas hedges proposed by the investor-owned utilities who are managing the Department's contracts. These hedging arrangements were proposed to reduce exposure to a potentially volatile gas fuel supply market with potentially higher gas costs without these gas futures contracts.

**DWR Margin Requirements 2004 - 100% Hedge**

Month	NP Fuel <sup>1</sup>	SP Fuel <sup>1</sup>	Total Fuel <sup>1</sup>	Contracts	Cost/Contract <sup>2</sup>	\$/ Full Yr.	\$/ 7 Mon	\$/High 7 Mon
Jan'04	504,284	13,755,653	14,259,937	1426	6750	\$9,625,458	\$9,625,458	
Feb'04	324,741	11,750,131	12,074,872	1207	6750	\$8,150,539	\$8,150,539	
Mar'04	295,573	9,554,868	9,850,441	985	6750	\$6,649,048	\$6,649,048	
Apr'04	290,057	9,583,746	9,873,803	987	6750	\$6,664,817	\$6,664,817	
May'04	20,397	8,457,372	8,477,769	848	6750	\$5,722,494	\$5,722,494	
Jun'04	97,111	11,958,824	12,055,935	1206	6750	\$8,137,756	\$8,137,756	\$8,137,756
Jul'04	1,568,020	13,607,474	15,175,493	1518	6750	\$10,243,458	\$10,243,458	\$10,243,458
Aug'04	1,922,757	16,244,489	18,167,245	1817	6750	\$12,262,891		\$12,262,891
Sep'04	1,820,490	14,074,808	15,895,298	1590	6750	\$10,729,326		\$10,729,326
Oct'04	1,026,815	13,510,003	14,536,817	1454	6750	\$9,812,352		\$9,812,352
Nov'04	1,150,279	13,384,521	14,534,800	1453	6750	\$9,810,990		\$9,810,990
Dec'04	1,187,727	13,875,792	15,063,519	1506	6750	\$10,167,876		\$10,167,876
<b>TOTAL</b>						<b>\$107,977,003</b>	<b>\$55,193,569</b>	<b>\$71,164,648</b>

<sup>1</sup> Fuel volumes as per ProSym run 42

<sup>2</sup> Assuming all volumes are hedged based upon a NYMEX *futures* non-members initial margin cost of \$6,750/contract.

**DWR's proposed determination must be based on a remittance methodology that prevents charging customers more than DWR's actual variable costs for additional power sales**

**Comment 17:** Incremental cost increases and decreases in remittance should exactly match the incremental change in DWR's actual costs due to changes in the amount of power sold by DWR under its contracts, relative to what DWR forecasts when it adopts its revenue requirement.

**Response:**

The Department does not file a revenue requirement to collect more than the costs it incurs. If there are temporary over-collections based on variances between forecast and actual costs and between forecast and actual volumes of energy supplied by the Department, then future rates for Department-supplied power are modified to net out any prior period over-collections such that remittances received from retail customers are equal to the actual costs incurred by the Department.

**I. Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations**

<b>Volume</b>	<b>Record Number</b>	<b>Record Title</b>
DWR04pRR	1	Index of Record of 2003 Revenue Requirement Reasonableness Determination, Submitted April 1, 2003 in PGE vs CDWR Case 02CS01631 Superior Court of California, County of Sacramento
DWR04pRR	2	Supplemental Determination of Revenue requirement for the Period January 1, 2003 through December 31, 2003 dated July 1, 2003,
DWR04pRR	3	Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations for the 2003 Supplemental Determination of Revenue requirement for the Period January 1, 2003 through December 31, 2003 dated July 1, 2003,
DWR04pRR	4	DWR Reconciliation of 2004Revenue Requirements Work-Paper
DWR04pRR	5	Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003
DWR04pRR	6	Southern California Edison Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003

DWR04pRR	7	San Diego Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of 2003 Revenue Requirement, dated June 23, 2003
DWR04pRR	8	CPUC Decision 02-11-074, November 21, 2002. "Order Granting Rehearing to Modify D.02-10-063". After reviewing the (several) applications for Rehearing and the responses, we are of the opinion that rehearing should be granted in order to exempt from the bond charge all residential sales up to 130% of baseline in all three service territories. Excluding the 130%, leads to an estimate that all other bundled consumption will pay a projected charge of between 0.7927 and 1.0732 cents per kWh in 2003 and between 0.7381 and 0.9141 cents per kWh in 2004.
DWR04pRR	9	CPUC Decision 02-12-082, December 30, 2002. "Order Granting Rehearing of Decision 02-11-074". The Rehearing decision Applies the Bond Charge to Residential Sales of Up to 130% of Baseline Usage in All Three Service Territories. The previous order had exempted residential sales of up to 130% of baseline.
DWR04pRR	10	CPUC Decision 03-02-036, February 13, 2003. "Order Denying Rehearing of Decision 02-12-082". This decision denies TURN's application for rehearing related to Commission decision(s) on the 130% of baseline issue in the bond charge proceeding.
DWR04pRR	11	CONFIDENTIAL - PROSYM Output. Run 42 and 43 Proprietary Model and Confidential Data contained and not for public release - Protected under relevant Non Disclosure Agreements. NOT FOR PUBLIC RELEASE
DWR04pRR	12	CONFIDENTIAL - PROSYM Output Run 42 and 43 Sensitivity Case 1, Proprietary Model and Confidential Data contained and not for public release - Protected under relevant Non Disclosure Agreements. NOT FOR PUBLIC RELEASE
DWR04pRR	13	CONFIDENTIAL - PROSYM Output Run 42 Sensitivity Case 2, Proprietary Model and Confidential Data contained and not for public release - Protected under relevant Non Disclosure Agreements. NOT FOR PUBLIC RELEASE

***Supplemental Material***

DWR04pRR	14	CONFIDENTIAL - Consultant's Financial Model version G3V27 and G3V28 Proprietary Model and Confidential Data contained and not for public release - Protected under relevant Non Disclosure Agreements. NOT FOR PUBLIC RELEASE
DWR04pRR	15	DWR Response to Comments and Data Requests in the DWR 2003 Supplemental CPUC Process
DWR04pRR	16	CPUC Resolution E-3825 dated July 10, 2003: Approval of PG&E gas tolling plan as modified
DWR04pRR	17	CPUC Resolution E-3833 dated July 10, 2003: Approval of SCE gas tolling plan as modified
DWR04pRR	18	CPUC Resolution E-3838 dated July 10, 2003: Approval of SGD&E gas tolling plan as modified

DWR04pRR	19	Preliminary Natural Gas Market Assessment: California Energy Commission staff report Dated May 27, 2003
DWR04pRR	20	CDWR Internal Memo Regarding Draft Fuels Protocols
DWR04pRR	21	CONFIDENTIAL - Work paper on 2004 Gas Collateral requirements - NOT FOR PUBLIC RELEASE
DWR04pRR	22	CONFIDENTIAL – Hedging Impact on Stress Case: Navigant Consulting Memo Dated April 15, 2003 – NOT FOR PUBLIC RELEASE
DWR04pRR	23	CONFIDENTIAL PG&E Gas Supply Plan for CDWR Tolling Agreements: Electric Advice Letter 2359-E – March 1, 2003 - NOT FOR PUBLIC RELEASE
DWR04pRR	24	CONFIDENTIAL - PG&E Gas Supply Plan for CDWR Tolling Agreements, Electric Advice Letter 2359-E-A, Supplemental Filing, March 25, 2003 Updated per Resolution E-3825 Updated July 21, 2003 NOT FOR PUBLIC RELEASE
DWR04pRR	25	CONFIDENTIAL - SCE Gas Supply Plan for CDWR Tolling Agreements - NOT FOR PUBLIC RELEASE
DWR04pRR	26	CONFIDENTIAL - SDG&E Gas Supply Plan for CDWR Tolling Agreements - NOT FOR PUBLIC RELEASE
DWR04pRR	27	Memo regarding DWR Data Response to Alliance Capital Management - Public Work Paper regarding Capacity Additional data May 21, 2003
DWR04pRR	28	Press Release For Renegotiated Contracts Dated 4/22/02 regarding Calpine, High Desert Power Project, Capitol Power, Cabazon, White Water Hill.
DWR04pRR	29	Press Release For Renegotiated Contracts Dated May 2, 2002 regarding CalPeak Power
DWR04pRR	30	Press Release For Renegotiated Contracts Dated August 27, 2002 regarding GWF
DWR04pRR	31	Press Release For Renegotiated Contracts Dated 11/11/2002 regarding Williams
DWR04pRR	32	Press Release For Renegotiated Contracts Dated December 23, 2002 regarding Clearwood Electric Company LLC, Wellhead Power LLC, and County of Santa Cruz
DWR04pRR	33	Press Release For Renegotiated Contracts Dated December 31, 2002 regarding Sunrise Power
DWR04pRR	34	Press Release For Contracts Dated January 14, 2003 regarding Kings River
DWR04pRR	35	Press Release For Renegotiated Contracts Dated 6/10/2003 regarding Allegheny Energy Supply Company
DWR04pRR	36	Press Release For Renegotiated Contracts Dated 6/26/2002 regarding El Paso
DWR04pRR	37	Press Release For Renegotiated Contracts Dated 7/11/2003 regarding Morgan Stanley
DWR04pRR	38	CDWR Preparation Guide for Update-to-Actuals

DWR04pRR	39	CONFIDENTIAL - Off System Sales Pricing work paper dated May 23, 2003 - NOT FOR PUBLIC RELEASE
DWR04pRR	40	CONFIDENTIAL - SCE 2003 Electricity Sales Plan -NOT FOR PUBLIC RELEASE
DWR04pRR	41	2002 BSA Audit Report
DWR04pRR	42	Memorandum from Pete Garriss, Deputy Director CERS, CDWR to CPUC Commissioner Brown regarding Allocation of 2003 Supplemental Revenue Requirement Determination, Dated August 4, 2003
DWR04pRR	43	Morgan Stanley Capital Group Renegotiated Long-term Contract with CDWR, Settlement Agreement, Confirmation Agreement
DWR04pRR	44	Allegheny Energy Supply Company Renegotiated Long-term Contract with CDWR, Settlement Agreement
DWR04pRR	45	Sunrise Power Company, LLC Settlement Agreement, and Confirmation Agreement
DWR04pRR	46	Wellhead Power LLC Settlement Agreement
DWR04pRR	47	Williams Energy Marketing & Trading Settlement Agreement, and Associated Renegotiation Documents
DWR04pRR	48	PG&E Energy Trading – Power Settlement Agreement
DWR04pRR	49	GWF Energy LLC Settlement Agreement
DWR04pRR	50	CalPeak Power LLC Settlement Agreement
DWR04pRR	51	CalPine Energy Services LP Settlement Agreement
DWR04pRR	52	Constellation Power Source /HDPP LLC Settlement Agreement
DWR04pRR	53	Colton Power LP Settlement Agreement
DWR04pRR	54	PG&E Data Request submitted during the APA Review Process of the 2004 Proposed Revenue Requirement, Dated July 29, 2003
DWR04pRR	55	Letter Response to PG&E from Andrew Ulmer, Dated July 31, 2003 Re: DWR 2004 Proposed Revenue Requirement Determination. This letter confirms the receipt of the Data Request submitted during the APA Review Process of the 2004 Proposed Revenue Requirement and confirms the scheduling of a Conference Call at the request of PG&E to Review Financial Model.

***Material Available at the Time the 2004 CDWR Revenue Requirement is Filed with the CPUC***

DWR04RRd	56	Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2004 Through December 31, 2004, dated August 14, 2003
DWR04RRd	57	San Diego Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2004 Through December 31, 2004,

dated August 14, 2003

DWR04RRd	58	Southern California Edison Company's Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2004 Through December 31, 2004, dated August 14, 2003
DWR04RRd	59	Bureau of State Audits Response to Public Records Request from PGE regarding DWR
DWR04RRd	60	Department of Water Resources Revenue Requirement Just and Reasonableness Determination Regulations Table of Contents (And supporting materials) for the Department of Water Resources Rulemaking File, Procedures for Making a Just and Reasonable Determination, June 4, 2003
DWR04RRd	61	Contract Provisions for Termination Payment Generally Found in DWR Power Purchase Agreements Work Paper
DWR04RRd	62	Transmission Considerations Work Paper – Except from Independent Consultants Report Appendix iii
DWR04RRd	63	100 FERC 61,060 Order on California Comprehensive Market Redesign Proposal, Issued July 17, 2002, California Independent System Operator Corporation Docket No. ER02-1656-000, Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Electricity Coordinating Council Docket No. EL01-68-017
DWR04RRd	64	California ISO Market Design 2002, Steve Greenleaf, Director of Regulatory Policy CAISO, CAISO Governing Board Meeting, June 26 2003,
DWR04RRd	65	Assembly Bill No. 57, Chapter 835 Approved by Governor September 24, 2002  AB 57 provided for each of the utilities whose customers are served energy by the Department to resume procurement of the energy requirements of their customers that are not served by the Department, beginning January 1, 2003. The legislation further required each utility to provide to the Commission an energy procurement plan, including a description of the required energy products and a procurement plan for the utilities to meet their residual net short energy needs.
DWR04RRd	66	CPUC Decision 03-04-029 April 3, 2003, Decision on Motions to Approve Operating Agreements
DWR04RRd	67	Blended costs include cost of Power purchased in the Spot market and from long term power contracts, Department of Water Resources – California Energy Resources Scheduling – Power Purchases Through January 2001 – October 2001
DWR04RRd	68	Hour Ahead and Monthly Actuals from ISO OASIS Data, July 1998 through August 2003.
DWR04RRd	69	Chronology of DWR Spot Price Forecast March 2001-June 2001, Simplified Model and PROSYM Model
DWR04RRd	70	Internal Memo From Gordon Pickering to Frank Perdue regarding Fuel Price Impacts May 8 2003

Impacts, May 8, 2003

DWR04RRd	71	Internal Memo From Jeff Van Horne to Ron Nichols regarding Least Cost Dispatch, September 10, 2003
DWR04RRd	72	CPUC Decision 03-09-017, September 4, 2003, Opinion Regarding Under Remittances
DWR04RRd	73	CPUC Decision 03-09-018, September 4, 2003, Order Implementing Allocation of the Supplemental 2003 Revenue Requirement Determination of the California Department of Water Resources
DWR04RRd	74	Department of Water Resources, California Energy Resources Scheduling Letter to Pacific Gas and Electric dated September 9, 2003 regarding Remittance By Pacific Gas and Electric Company to the California Department of Water Resources of \$77,258,189 pursuant to Ordering Paragraph 6 of Decision 03-09-018 (DWR Bank Account Number Redacted)
DWR04RRd	75	Pacific Gas and Electric Letter to Department of Water Resources dated September 11, 2003 regarding Remittance of \$77,258,189 Pursuant to Decision 03-09-018
DWR04RRd	76	CONFIDENTIAL - Average Daily Absolute Differenced Between IOU Day-Ahead and Hour-Ahead Net Short Forecasts Q4 2001 and 2002 NOT FOR PUBLIC RELEASE
DWR04RRd	77	CONFIDENTIAL IOU Q4 2001 and 2002 Forecast Changes NOT FOR PUBLIC RELEASE
DWR04RRd	78	CONFIDENTIAL PGE Load, Resources, and Net Short Analysis, Lowering Costs by Modifying PG&E's Hydro Dispatch and Net Short, CERS March 6, 2002 NOT FOR PUBLIC RELEASE
DWR04RRd	79	CONFIDENTIAL SCE Load, Resources, and Net Short Analysis – Review of Method to Lower Power Costs by Modifying SCE's Hydro Dispatch and Net Short, CERS, April 12, 2002 NOT FOR PUBLIC RELEASE
DWR04RRd	80	CONFIDENTIAL Review of SCE Forecast Information, Electric Power Group, December 17, 2001 – Confidential NOT FOR PUBLIC RELEASE
DWR04RRd	81	CONFIDENTIAL - E-mail correspondence regarding coordination with IOUs and forecast information NOT FOR PUBLIC RELEASE
DWR04RRd	82	CONFIDENTIAL – CDWR Off System Sales Revenue Excerpt from Consultants Financial Model (source: CFMG3v29o.xls) - NOT FOR PUBLIC RELEASE
DWR04RRd	83	CONFIDENTIAL – Department of Water Resources – California Energy Resources Scheduling - Power Purchase and Sales Data - NOT FOR PUBLIC RELEASE
DWR04RRd	84	COPYRIGHTED MATERIAL - Global Insight DRI pro database Power Market Week/Platt's Historic Daily Spot Prices Peak and Off Peak, North Path 15, South Path - NOT FOR PUBLIC REDISTRIBUTION
DWR04RRd	85	COPYRIGHTED MATERIAL - Natural Gas Prices – California Price Study January 1, 1999 through September 4, 2003– Daily Spot Prices, Monthly Index

Prices, Future Prices - NOT FOR PUBLIC REDISTRIBUTION

DWR04RRd	86	Bloomberg Energy Data NYMEX Futures Natural Gas Monthly Closing Price January 2002 through 2004, Closing Futures Records Starting February 28, 2001 to Date - NOT FOR PUBLIC REDISTRIBUTION © 2002 Bloomberg L.P. Reprinted with permission. All rights reserved. Visit <a href="http://www.Bloomberg.com">www.Bloomberg.com</a> .
DWR04RRd	87	Bloomberg Energy Data NYMEX Futures Natural Gas January 1, 2001 to March 22, 2002 - NOT FOR PUBLIC REDISTRIBUTION © 2002 Bloomberg L.P. Reprinted with permission. All rights reserved. Visit <a href="http://www.Bloomberg.com">www.Bloomberg.com</a> .
DWR04RRd	88	COPYRIGHTED MATERIAL- Platts Gas Daily, The McGrawHill Companies Daily Spot Gas Price Malin, PGE City Gate, Socal Border February 1, 1998 through September 4, 2003 NOT FOR PUBLIC REDISTRIBUTION
DWR04RRd	89	CONFIDENTIAL - Q1-Q3 2001 CDWR Net Short Forecasts and Actual Purchases – NOT FOR PUBLIC RELEASE